The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

November 29, 1996

D.P.U. 96-50 (Phase I)

Investigation by the Department of Public Utilities on its own motion as to the propriety of the rates and charges set forth in the following tariffs: M.D.P.U. Nos. 944 through 970, filed with the Department on May 17, 1996, to become effective June 1, 1996, by Boston Gas Company; and investigation of the proposal of Boston Gas Company to implement performance-based ratemaking, and a plan to exit the merchant function.

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I. INTRODUCTION

A. Procedural History

On May 17, 1996, Boston Gas Company ("Boston Gas" or "Company") filed with the Department of Public Utilities ("Department") tariff schedules of proposed rates and charges designed to increase the Company's annual retail revenues by approximately $25.73 million, or 4.7 percent, based on a test year ending December 31, 1995. The Company also filed a request for approval of (1) a performance-based ratemaking ("PBR") plan providing for an initial increase of approximately $6.8 million, (2) a transition plan for the full unbundling of gas commodity sales and gas distribution services to all customers to be phased in by the Company over a four-year period and (3) a plan to exit the merchant function by November, 2000. The matter was docketed as D.P.U. 96-50. By Order dated May 23, 1996, the Department suspended the effective date of the proposed tariffs until December 1, 1996, in order to investigate the propriety of the changes sought by the Company. The Department last granted Boston Gas a rate increase of $39 million pursuant to the Order in Boston Gas Company, D.P.U. 93-60 (1993).

Boston Gas supplies gas service to approximately 532,000 customers in 78 communities, primarily located in the greater Boston area, and extending to Leominster and the central part of the Commonwealth (Exh. AG-10). Boston Gas is a wholly-owned subsidiary of Eastern Enterprises, Inc. ("Eastern"), a holding company with other operating businesses in marine transportation, waterworks component distribution, water purification systems, and a newly formed energy marketing company, *ALL*Energy Marketing Company, Inc. ("AllEnergy") (Exh. DOER-4). Boston Gas's wholly owned subsidiary, Massachusetts

LNG, Inc., is engaged in the supply of liquified natural gas ("LNG") service. Boston Gas also supplies gas at wholesale to other gas utilities in Massachusetts.

Pursuant to notice duly issued, the Department conducted three public hearings in the Company's service territory on June 26, June 27, and July 18, 1996, in Revere, Leominster and Newton, respectively, in order to afford interested persons an opportunity to comment on the proposed rates, PBR plan, transition plan, and exit plan. The Department conducted 24 days of evidentiary hearings at the Department's offices between July 22, 1996 and September 18, 1996. Pursuant to G.L. c. 12, § 11E, the Attorney General of the Commonwealth filed a notice of intervention in the proceeding. In addition the Department granted petitions to intervene on behalf of the following entities: Alberta Energy Company Limited, Progas Limited, Producers Marketing Limited, and TransCanada Gas Services ("TransCanada") (collectively, "Canadian Marketers"); Algonquin Gas Transmission Company ("Algonquin"); AllEnergy; Amoco Corporation; Associated Industries of Massachusetts ("AIM"); Bay State Gas Company ("Bay State"); Berkshire Gas Company ("Berkshire"); City of Boston; Commonwealth Gas Company ("ComGas"); Direct Energy Marketing, Inc.; Distrigas of Massachusetts Corporation ("Distrigas"); Commonwealth of Massachusetts Division of Energy Resources ("DOER"); Eastern Energy Marketing, Inc.; the Energy Consortium ("TEC"); Enron Capital and Trade Resources Corp. ("Enron"); ERI Services, Inc.; Essex County Gas Company ("Essex"); Fall River Gas Company ("Fall River"); Global Petroleum ("Global"); Imperial Oil Resources ("Imperial"); KEYSPAN Energy Services, Inc.; the Town of Lexington; Massachusetts Oil Heat Council ("MOC");

Natural Gas Clearinghouse; Northeast Energy Efficiency Council ("NEEC");[1] Pearl Noorigan and Samuel Graziano ("Low-Income Intervenors"); North Attleboro Gas Company ("North Attleboro"); PanEnergy Trading and Market Services, LLC; Texas Eastern Transmission Company ("TETCO"); Texas-Ohio Gas, Inc. ("Texas-Ohio"); United States Gypsum Company ("US Gypsum"); and Utilicorp United, Inc. The Department granted limited participant status to the following entities: Colonial Gas Company ("Colonial"); Massachusetts Electric Company ("MECo"); Tennessee Gas Pipeline Company, Inc. ("Tennessee"); and Total/Louis Dreyfuss Energy Services, L.L.C.

In support of its filing, the Company presented testimony of fourteen witnesses: Chester R. Messer, president of Boston Gas; Joseph F. Bodanza, vice president of finance for Boston Gas; Robert M. Miller, vice-president of marketing and operation for Boston Gas; Rebecca S. Bachelder, manager of accounting and rates for Boston Gas; Jane M. Kelly, director of accounting for Boston Gas; William T. Yardley, manager of gas acquisition and system control for Boston Gas; David A. Heintz, director, rates and revenue analysis for Boston Gas; Robert J. Steele, group leader, energy management for Boston Gas; Samir Mishra, rate analyst for Boston Gas; Paul M. DeRosa, rate analyst for Boston Gas; Theodore Poe, rate analyst for Boston Gas; Mark N. Lowry, vice president of Christensen Associates; Paul R. Moul, senior vice president, AUS Consultants; Ernest R. Berndt, professor of applied economics, Massachusetts Institute of Technology; David S. Sibley, professor of economics, University of Texas. Boston Gas also presented the rebuttal testimony of Charles J. Cicchetti, managing director of Arthur Andersen Consulting.

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[1] On September 25, 1996, the Massachusetts Energy Efficiency Council changed its name to the Northeast Energy Efficiency Council.

DOER presented the testimony of three witnesses: Barbara Kates-Garnick and Amy Bertin Candell of Economics Resource Group; and Mark C. Pocino, vice president of Reed Consulting Group. Bay State presented the testimony of Joel L. Singer, president and chief operating officer of Bay State. Distrigas sponsored the testimony of Jane P. Michalek, vice president of Distrigas. US Gypsum presented the testimony of Robert Cooper, energy manager for US Gypsum. Texas-Ohio presented the testimony of Douglas O. Short, president of Douglas Short Consulting, Inc. TEC presented the testimony of Robert C. Rossingnol, director of energy management for The Flatley Company. Enron sponsored the testimony of Steven Montovano, director of state regulatory affairs.

The evidentiary record consists of 245 Boston Gas exhibits, three AllEnergy exhibits, 14 Algonquin exhibits, 295 Attorney General exhibits, one Bay State exhibit, 86 DOER exhibits, 17 Distrigas exhibits, two Enron exhibits, six Imperial exhibits, eight Low-Income Intervenor exhibits, 18 MOC exhibits, 13 TEC exhibits, eleven TETCO exhibits, 45 Marketer Group ("TMG")[2] exhibits, one Texas-Ohio exhibit, one US Gypsum exhibit, and 218 Department exhibits. The record also contains 206 responses to record requests submitted by Algonquin, the Attorney General, Bay State, the City of Boston, Distrigas, DOER, Global, Imperial, MOC, TEC, TMG, and US Gypsum.

The following parties filed initial briefs in this matter: Boston Gas, AIM, Algonquin, AllEnergy, the Attorney General, Bay State, City of Boston, ComGas, Distrigas, DOER, Enron, Essex, Imperial, Low-Income Intervenors, MOC, NEEC, TEC, Tennessee, TMG, TransCanada, and US Gypsum. The following parties filed reply briefs: Boston Gas, AIM,

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2 The following intervenors comprise TMG: Direct Energy Marketing, Inc., Eastern Energy Marketing, Inc., KEYSPAN Energy Services, Inc., PanEnergy Services, Inc., and Utilicorp United, Inc. (Motion for Clarification of TMG at 1).

Algonquin, the Attorney General, Berkshire, City of Boston, ComGas, Distrigas, DOER, Essex, MOC, NEEC, TEC, Texas-Ohio, TMG, and US Gypsum.

B. Procedural Rulings

At the June 20, 1996, prehearing conference, the Department indicated that it would bifurcate the examination of the Company's petition by deferring the consideration of the Company's proposal to exit the merchant function to another phase of the proceeding ("Phase II") (Tr. of Prehearing Conference at 15). The Department stated, however, that it would address the Company's capacity assignment proposal in Phase I of the proceeding (id.).

On July 26, 1996, the Company filed a Motion for Clarification of the scope of the Department's investigation in Phase I ("Company Motion").[3] Pursuant to the Hearing Officers's Ruling issued on September 9, 1996, the Department indicated that it intends to address the following issues in Phase I of the proceeding: (1) the proposed revenue increase and all base-rate related issues; (2) the proposed price-cap mechanism; (3) the proposed commercial and industrial ("C&I") general transportation service and general transportation receipt service terms and conditions; (4) the capacity assignment method; (5) the proposed optional transportation service and optional transportation receipt terms and conditions; (6) the proposed interruptible transportation ("IT") buyout plan; (7) the proposed cost of gas adjustment clause ("CGAC") and local distribution adjustment ("LDAC") formulas; and (8) the proposed low-income demand-side management ("DSM") program. Boston Gas Company, D.P.U. 96-50, Hearing Officers's Ruling on Scope of Proceedings ("Hearing

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3 On August 2, 1996, TMG filed both a response to the Company Motion as well as a Motion for Clarification Concerning Market Affiliate Issues. The September 9, 1996, Hearing Officers's Ruling addresses TMG's August 2, 1996, filings.

Officers's Ruling on Scope") at 3 (September 9, 1996). The Department also cautioned that the disposition of certain issues in Phase I may be interim in nature pending the outcome of the Phase II proceeding.[4] Id. at 4.

On July 22, 1996, during hearings, the Company submitted three new exhibits consisting of an addition of $1.0 million to the Company's operating expenses for a customer communications proposal, and $1.8 million to rate base for a broker management system (Tr. 2, at 10-11). On July 24, 1996, the Attorney General objected to the addition of the adjustments to the Company's cost of service on the grounds that the new adjustments constituted new issues that the Company is introducing into the case (id. at 14-15). The Department found that the customer communications expense was not an update to a previously-filed schedule of the type routinely allowed by the Department, but rather a new addition to the Company's cost of service. Boston Gas Company, D.P.U. 96-50, Hearing Officer Ruling ("Hearing Officers's Ruling on Attorney General's Objection") at 5 (September 9, 1996). Further, the Department found that the broker management system is not an update to a previously-filed schedule of the type routinely allowed by the Department. Id. at 4. The Department, therefore, sustained the Attorney General's Objection to admission of these new adjustments. Id.

On October 9, 1996, the Company, Algonquin, Distrigas, Global, Natural Gas Clearinghouse,[5] Tennessee, and Texas-Ohio (collectively, "Settling Parties") filed with the

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4 The Department also shall defer consideration of the Company's proposed optional tariffs until Phase II of this proceeding.

5 By letter dated October 10, 1996, Gregory K. Lawrence, Esq., counsel of record for Natural Gas Clearinghouse, notified the Department of withdrawal of his appearance on behalf of Natural Gas Clearinghouse.

Department a Joint Motion for Approval of an Offer of Partial Settlement ("Joint Motion") and the Offer of Partial Settlement relating, inter alia, to terms, condition, rates, and charges for a range of services for C&I customers, including general transportation and general receipt services, optional transportation and optional receipt services, and balancing services. On October 11, 1996, the Department denied the Joint Motion of the Settling Parties. Boston Gas Company, D.P.U. 96-50 (Phase I) Ruling on Joint Motion (October 11, 1996).

C. Joint Motion for Approval of Offer of Partial Settlement

On November 15, 1996, the Company, AIM, the Attorney General, DOER, the Low-Income Intervenors and TEC filed with the Department a Joint Motion for Approval of Offer of Partial Settlement and an Offer of Partial Settlement (jointly "Settlement"). The Settlement addressed certain issues described as follows: (1) additional base rate revenues; (2) low-income discount; (3) ratemaking treatment of interruptible transportation margins; (4) pricing of interruptible transportation; (5) demand-side management spending; (6) effective date of compliance under any PBR; (7) cost allocation; (8) customer charges for the period December 1, 1996, through November 1, 1997; and (9) rate design for rate schedules G-44, G-45, G-54 and G-55. The Settlement was conditioned expressly on the Department's approval of all provisions as submitted.

In assessing the reasonableness of an offer of settlement, the Department must review the entire record as presented in a company's filing and other record evidence to ensure that the settlement is consistent with Department precedent and public policy. See Massachusetts Electric Company, D.P.U. 96-59, at 7 (1996); Western Massachusetts Electric Company, D.P.U. 96-8-CC at 6 (1996); Massachusetts Electric Company, D.P.U. 94-112, at 6 (1994); Fitchburg Gas and Electric Light Company, D.P.U. 92-181, at 12 (1993).

We acknowledge the efforts of the settling parties in reaching an agreement. However, based on our review of the extensive record in this case and our findings set forth in this Order, the Department finds that the Settlement does not serve the interest of ratepayers and, therefore, fails to meet the standard set forth above. Accordingly, the Department rejects the Settlement.

II. RATE BASE

A. Post-Test Year Plant Additions

1. Introduction

As of the end of the test year, Boston Gas's total net plant in service was $504,776,189 (Exh. BGC-39, at 4). Between 1993 and 1995, the Company had made approximately $158 million in capital investments for the purposes of increasing service quality, distribution system improvements, and lowering costs through productivity and operating-efficiency programs (Exh. BGC-38, at 12). Of this amount, Boston Gas considered $88,500,000 to be of a non-revenue producing nature, which the Company defined as investments, such as replacing existing mains and service lines, which do not result in increased throughput (id.; Tr. 2, at 43-44, 50).[6]

a. Non-revenue Producing Plant Additions

Citing the considerable capital investment it has made between 1993 and 1995, and the need to ensure that the "cast-off" rates under PBR will adequately reflect this level of spending, Boston Gas has proposed the addition of $28,056,000 in projected 1996 non-revenue producing system replacement investments to rate base (Exhs. BGC-38, at 12;

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6 For purposes of this proceeding, the Company has referred to its non-revenue producing plant, including mains, service lines, meters, and meter installations, as system replacement investments (Exhs. BGC-38, at 12; DPU-7).

DPU-5; RR-AG-59, at 6). The Company estimates that its non-revenue producing system investments will consist of $18,922,000 in mains, $8,015,000 in services, and $1,119,000 in meter replacements (RR-AG-59, at 6).[7] According to Boston Gas, the primary reason for these investments is the requirement to replace cast iron and bare steel mains pursuant to 220 C.M.R. § 113, and the requirement to replace meters pursuant to G.L. c. 164, § 115A (Tr. 2, at 46-47; Tr. 4, at 42). Because the Company's investments associated with increasing throughput on the distribution system are expected to pay for themselves, Boston Gas did not include revenue-producing plant investment in rate base (Exh. BGC-38, at 12; Tr. 2, at 50).

Boston Gas reduced its proposed gross investment by $670,539 to reflect the depreciation which will be taken on a half-year basis for system replacement plant items, using a composite accrual rate of 4.78 percent (Exhs. BGC-38, at 13; DPU-6; RR-AG-59, at 5). Additionally, the Company reduced its 1996 non-revenue producing investment by $19,386,292 to recognize the total depreciation to be taken during 1996 on system replacement plant that had been in service as of the end of the test year (Exh. BGC-38, at 13; RR-AG-59, at 5; Tr. 2, at 111). The Company determined this amount by applying the five-year average of system replacement spending as a percentage of total spending for related accounts, 70.61 percent, to the $27,455,448 annualized depreciation on plant in service as of the end of the test year (Exh. DPU-7; RR-AG-59, at 7). Therefore, the Company proposed the net addition of $7,999,169 to its year-end rate base.

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7 The Company explained that the bulk of its 1996 additions was made during the summer months (Tr. 2, at 105). Because street opening permits are not granted during the winter months, no system additions are anticipated after the date of this Order (id. at 105-106).

b. Performance Measurement Systems

The Company has invested and is continuing to invest in information technology related to performance measurement. According to Boston Gas, these systems will systematically measure performance, facilitate an understanding of underlying cost drivers, allow for more effective planning and resource allocation, and assist in establishing reasonable and cost-effective goals for the Company and its employees (Exh. BGC-38, at 14). According to the Company, these investments are essential for it to be successful in the competitive market (id). The Company placed into service on July 1, 1996 a financial applications system with a total final cost of $1,250,000 (Exhs. BGC-40; BGC-41; Tr. 2, at 10-11; Tr. 15, at 42). Among the other information systems scheduled to be placed into service during 1996 are a data warehousing package with a total estimated cost of $1,200,000, an activity-based cost management system with a total estimated cost of $200,000, and a budgeting system with a total estimated cost of $158,000 (Exhs. BGC-38, at 15-16; BGC-42; Tr. 2, at 11; Tr. 15, at 42-43). Boston Gas reported that it has been evaluating vendor bids for the data warehousing package, and is in the initial research stages for the activity-based cost management system (Tr. 11, at 103-105).

The total cost of these software packages is $2,808,000. As a corresponding adjustment, the Company proposed to remove $280,000 in amortizations associated with these software packages projected for 1996, thereby resulting in a net increase to rate base of $2,528,000 (Exh. BGC-38, at 14).

c. Telemetering Equipment

In its initial filing, Boston Gas proposed the installation of telemetering equipment to measure daily peak demands of customers to be served under two proposed optional rate

schedules (id. at 13-14). See Sections VI.E.6 and VI.E.10, below. The Company proposed the inclusion of $358,452 in plant investment, less $12,743 in depreciation expense to be taken during 1996, for a net increase to rate base of $345,709 (id.). On brief, Boston Gas states that in light of its evaluation of bill impacts, it would not be necessary to telemeter its optional service customers, and has withdrawn the proposed adjustment (Company Brief at 87, citing RR-DPU-51 (rev.) at 3).

d. Other Plant Adjustments

The Company removed from its year-end plant investment $6,449,661 in acquisition premiums associated with its purchase of several gas utilities from New England Electric System in 1972 and 1973, in accordance with Boston Gas Company, D.P.U. 17138 (1971) and Boston Gas Company, D.P.U. 17574 (1973) (Exhs. BGC-38, at 35; BGC-39, at 5). Additionally, Boston Gas removed from rate base $6,000,000 in capital lease obligations (Exhs. BGC-38, at 35; BGC-39, at 5).

2. Positions of the Parties

a. Attorney General

The Attorney General opposes the Company's proposed post-test year rate base additions. The Attorney General contends that the proposed additions are neither extraordinary, nor proportionately large and are in some cases, estimates and are, therefore, inconsistent with Department precedent (Attorney General Brief at 44-45, 48-49). The Attorney General observes that in the incentive regulation decision, the Department specifically directed utilities to present PBR proposals which conform with existing Department regulations and precedent (id. at 23, citing Incentive Regulation, D.P.U. 94-158 ("Incentive Regulation"), at 58 (1995)). The Attorney General maintains that the Company's

assertion that these additions are needed to ensure a "proper" cast-off point for PBR is unsupported by either the record or Department precedent, and suggests that Boston Gas's proposal is merely an attempt to reap the maximum benefits for the Company's competitive activities at the expense of its regulated operations (Attorney General Brief at 43-44; Attorney General Reply Brief at 23-24).

The Attorney General contends that acceptance of the Company's proposal would allow Boston Gas to recover test year-end rate base, higher depreciation rates, and post-test year additions and, therefore, constitute double or triple recovery for the same expenses (Attorney General Brief at 46-47; Attorney General Reply Brief at 24-25). Furthermore, the Attorney General contends that the Company's proposal is asymmetrical because it seeks to charge ratepayers for system-enhancing, non-revenue producing mains and service additions while failing to account for other revenue-producing investments (Attorney General Brief at 47). The Attorney General further contends that if post-test year additions are recognized, they must be accompanied by the recognition of revenues generated by such investments (id., citing Boston Edison Company, D.P.U. 18515, at 5-7 (1976) and Boston Edison Company, D.P.U. 18200/18200-A at 16 (1975)). The Attorney General criticizes the Company's selectivity in proposed rate base additions because the Company's revenue-producing investments have produced internal rates of returns ("IRRs") far in excess of its overall cost of capital (id. at 47-48).

b. DOER

DOER opposes the Company's proposed rate base additions. DOER argues that Department precedent requires the use of year-end plant in service to determine rate base (DOER Brief at 7, citing AT&T Communications of New England, Inc., D.P.U. 85-135,

at 13-14 (1985) and Boston Edison Company, Policy Statement of the Commission Concerning the Adoption of Year-End Rate Base, D.P.U. 160 (1980)). According to DOER, a departure from this precedent must be based on a demonstration that the proposed addition represents a significant investment which has a substantial impact on the utility's rate base (id. at 7-8, citing Massachusetts-American Water Company, D.P.U. 95-118, at 40-41 (1996); Western Massachusetts Electric Company, D.P.U. 85-270, at 62-63, 140-141 (1986); Massachusetts-American Water Company, D.P.U. 1700, at 5-6 (1984); Western Massachusetts Electric Company, D.P.U. 1300, at 14-15 (1983)). DOER contends that the Company's proposed rate base additions are not significant in relation to its total rate base, and, therefore, would not qualify for inclusion as a post-test year plant addition (id. at 8).

Furthermore, DOER asserts that the Company's arguments on this issue are wholly inconsistent with the concept of performance-based regulation (id.). According to DOER, the Department has found that the concept of cost recovery, as requested by Boston Gas, is directly counter to the performance-based regulatory approach (id. at 8-9, citing Incentive Regulation at 61-62).

c. The Company

The Company contends that the Attorney General and DOER fail to understand the special nature of PBR and the need to develop appropriate starting rates (Company Brief at 92). Boston Gas explains that under PBR, the Company bears the risk for cost recovery of investments made in non-revenue producing assets after the implementation date of the PBR (id. at 92, citing Exh. DPU-11; Company Reply Brief at 39-40). Unless investments in non-revenue producing assets made between the end of the test year and the implementation date of the PBR are included in the "cast-off" point, Boston Gas argues that the associated

costs will never be recovered from ratepayers (Company Brief at 92). The Company contends that the Department's Order in Incentive Regulation is not as inflexible as the Attorney General claims, and notes that no specific method or theory was required to fulfill the statutory obligation to achieve just and reasonable rates (Company Reply Brief at 38-38, citing Incentive Regulation at 43-44).

Regarding the Attorney General's argument that the proposed adjustment is asymmetrical by its failure to include revenue-producing plant additions, the Company maintains that revenue-producing investments are discretionary in nature and, as such, Boston Gas bears the risk of those investments (Company Brief at 94; Company Reply Brief at 39). Thus, the Company contends that its post-test year revenue-producing investments are appropriately excluded from rate base (Company Brief at 94-95).

With respect to the Attorney General's arguments on double- and triple-recovery, Boston Gas claims that the Attorney General appears to be arguing that the higher negative salvage values approved in the Company's last rate case obviate the need for rate base inclusion of its post-test year non-revenue producing additions (Company Brief at 93). Boston Gas argues that its ratepayers will not "pay" for revenue-producing additions because under PBR, the link between costs and prices is severed (Company Reply Brief at 39). The Company argues that the evidence relied upon by the Attorney General fails to support his contention, and that the higher negative salvage values approved in D.P.U. 93-60 were designed to reflect the higher costs of property removal versus a need to compensate for Boston Gas's plant reconstruction programs (Company Brief at 93-94, citing Exh. AG-55, at III-7, III-9).

3. Analysis and Findings

For ratemaking purposes, the Department determines rate base according to the cost of the utility's plant in service as of the end of the test year under a used and useful standard. In order to qualify for inclusion in rates, a utility's plant investment must be in service and providing benefits to customers. D.P.U. 85-270, at 60. With respect to plant installed after the end of the test year, it is the Department's policy not to adjust year-end rate base unless the utility demonstrates that the addition represents a significant investment which has a substantial impact on a company's rate base. D.P.U. 95-118, at 41; D.P.U. 85-270, at 141 n.21; D.P.U. 1122, at 19.

Boston Gas's claim that exclusion of its post-test year non-revenue producing system investments from rate base will cause it to permanently forgo a return on this investment is based on its assumption that its PBR will be extended automatically at the end of the initial term without modification.[8] The Department finds that the mere fact that a PBR mechanism will be adopted through this Order does not warrant an exception to our post-test year standard on rate base additions. Under cost of service regulation, excluded post-test year rate base additions would qualify for inclusion in rate base in the utility's subsequent rate application, assuming that they otherwise meet the Department's used and useful standards. Similarly, PBR mechanisms are designed with a specific term of operation, and could be subject to modification based on actual experience. It is premature for the Company to assume that its PBR plan will be merely extended for another term, in the same form and substance as approved herein. By this Order, the Department has approved a five-year term

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8 Given the relative lack of experience with PBRs in the gas distribution industry, it would be speculative to presume what modifications, if any, a PBR approved in 1996 would require in the year 2001.

for Boston Gas's PBR plan. At the end of the term of the PBR approved herein, Boston Gas may propose modifications to the PBR.

With respect to the proposed post-test year non-revenue producing system additions, the Department finds that both individually and collectively these do not constitute an extraordinary addition to year-end rate base. Accordingly, the Department shall exclude $28,056,000 from gross plant in service and $20,056,831 ($670,539 + $19,386,292) from depreciation reserve, for a net reduction of $7,999,169 from Boston Gas's rate base.

With respect to the proposed performance measurement systems, the record demonstrates that only one of the four software packages, the financial applications system, is currently in service. The Department finds that the financial applications system does not constitute an extraordinary addition to year-end rate base. The record further demonstrates that the other performance measurement systems are not completed, and are therefore not in service. Moreover, the Department finds that the data warehousing package, the activity-based cost management system, and the budgeting system do not either individually or collectively constitute an extraordinary addition to year-end rate base. Accordingly, the Company's proposed rate base shall be reduced by an additional $2,528,000 ($2,808,000 - $280,000).

Insofar as the Company has withdrawn its proposed telemetering rate base addition, the Department shall exclude $349,705 ($358,452 - $12,743) from the Company's proposed rate base. Therefore, the Department shall exclude a total of $10,876,874 from rate base. Consistent with this treatment, the Department shall also exclude $1,453,000 from the Company's deferred income tax reserve, per Exhibit DPU-12. The associated depreciation expense is addressed in Section IV.P, below.

B. 1993-1995 Capital Investments

1. Introduction

Since 1992, Boston Gas has invested approximately $158 million in capital expenditures, including $126 million in new mains and services and $15 million in technology improvements such as automated meter reading ("AMR") (Exh. BGC-38, at 16-17). In addition to direct costs, the Company books indirect charges to capital projects, including supervision, other indirect charges, paving, police details, permits, employee benefits, other related expenses, and allowance for funds used during construction ("AFUDC") (RR-AG-32; Tr. 8, at 107). For budgeting purposes, these indirect charges are generally allocated to the various capital projects through application of a 45 percent adder to the project's direct costs (Exh. BGC-38, Sup. Vols. 1 through 7, passim; Tr. 8, at 107).

In the Company's last rate case, the Department faulted the Company for its failure to perform cost-benefit analysis of so-called "non-discretionary" investments. The Department directed the Company to: (1) use cost-benefit analysis or a similar management tool for all non-discretionary construction projects in excess of $100,000; (2) budget all indirect costs as part of its budget authorizations; and (3) support the project authorizations with sufficiently detailed cost-benefit analyses commensurate with the project's complexity and expense. D.P.U. 93-60, at 35-36. In the case of projects for which cost-benefit analysis may not be applicable, such as street main replacements, the Department placed the Company on notice that it expected the Company to demonstrate that it sought to contain the overall cost of such projects. D.P.U. 93-60, at 35 n.13.

In response to this directive, the Company provided as part of its initial filing the capital authorization and closed work order reports for approximately 300 projects which

were completed between 1993 and 1995 at a total cost in excess of $50,000 each (Exhs. BGC-38, at 17; BGC-43). The aggregate cost of these projects was $70.9 million (Exh. BGC-43).

a. Revenue-Producing Investments

In addition to the capital authorization and closed work order reports, Boston Gas provided cost-benefit analyses for those investments made between 1993 and 1995 which were intended to increase throughput (e.g., revenue-producing investments) (id.). According to the Company, the aggregate returns of those projects which have been in service for a sufficient period to produce usable data demonstrates that Boston Gas achieved an overall IRR of 359.0 percent in 1993 and 112.4 percent in 1994 (Exh. BGC-44).[9] On an aggregate basis for other revenue-producing investments made between 1993 and 1995, Boston Gas reported that it achieved aggregate IRRs of 61.9 percent in 1993, 70.0 percent in 1994, and 55.5 percent in 1995 (Exhs. BGC-38, at 17-18; BGC-45).

During 1993 and 1994, three of Boston Gas's revenue-producing investments, the Ruggles Center project, the Brighton High School project, and the Wayland Schools project, produced IRRs which either were negative or less than the Company's overall required rate of return ("ROR") (Exh. BGC-44). The Company originally estimated that the Ruggles Center project would require a net capital investment of $18,535 ($30,711 less contributions in aid of construction ("CIAC") of $12,176) and result in annual consumption of 6,156 one thousand cubic feet ("Mcf") (Exh. BGC-38, Supp. Vol. 1, "Mains - New Construction"). Based on the final construction costs, the project's total capital costs were $68,903 with

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9 The IRRs for 1993 ranged between a negative 16.5 percent and a positive 450.0 percent, while the IRRs in 1994 ranged between a positive 4.9 percent and a positive 536.0 percent (Exh. BGC-44).

annual consumption of 2,269 Mcf, for an IRR of -7.6 percent (id.).[10] The Company originally estimated that the Brighton High School project would require a net capital investment of $187,133 ($211,033 less CIAC of $23,900) and result in annual consumption of 23,200 Mcf for a seven-school project (id.). Based on the final construction costs, the Brighton High School portion of the project total capital costs was $57,432 with annual consumption of 1,674 Mcf, for an IRR of -16.50 percent (id.). The Company originally estimated that the Wayland Schools project would require a net capital investment of $84,583 ($134,583 direct costs, less CIAC of $50,000), and result in annual consumption of 25,181 Mcf for a three-school project (Exh. BGC-38, Supp. Vol. 2, "Mains - Relay Customer").[11] Based on the final construction costs, the project's capital costs were $264,131 with annual consumption of 13,502 Mcf, for an IRR of 4.90 percent (id.; BGC-44). Boston Gas received contributions in aid of construction for each of these projects (Exhs. BGC-38, Supp. Vol. 1, "Mains - New Construction," Supp. Vol. 2, "Mains - Relay Customer"). None of the parties addressed this issue on brief.

b. Non-revenue Producing Additions

With respect to non-revenue producing investments, the Company described its ongoing cost containment efforts (id. at 18-20). Boston Gas noted its automated mains management system used to prioritize reconstruction schedules, to coordinate main reconstruction with local street reconstruction efforts, and to facilitate the Company's

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10 The Company noted that because of air quality problems in the building, the intended tenant, the Registry of Motor Vehicles, has vacated the premises (Exh. BGC-38, Supp. Vol. 1, "Mains - New Construction").

11 The street authorization report includes only direct costs and CIAC; the report omits indirect costs (Exh. BGC-38, Sup. Vol. 2, "Mains - Relay Customer")

cathodic protection program has served to reduce costs (id. at 18; Exh. DPU-63; Tr. 4, at 40-42; Tr. 21, at 187). Boston Gas stated that its formal competitive bid document and process facilitates bid review and reduces processing time (Exh. BGC-38, at 19). The Company also pointed to its plastic pipe bidding process used to reduce inventory carrying costs, as well as to its use of trenchless technology and other new technologies designed to reduce main replacement costs, as reducing overall costs (id. at 19; Tr. 16, at 203-204). Finally, Boston Gas noted that it has successfully litigated, and continues to pursue legal remedies, against what it considers to be unreasonable local permit requirements, including excessive permit fees and the mandatory use of specific contractors (Exh. BGC-38, at 19-20). None of the parties addressed this issue on brief.

c. Vehicular Natural Gas Facilities

Boston Gas currently owns two vehicular natural gas ("VNG") stations located at its facilities in Everett and Rivermoor (id., Supp. Vols. 4 and 7, "Special Projects"; Tr. 12, at 11-12). The Company primarily uses these stations to serve its fleet vehicles, and permits its customers to use them on a limited basis. CNG Rulemaking, D.P.U. 92-230, at 4-5 (1993).

In 1994, the Company entered into a joint agreement with Shell Oil Company to share the expense of designing and constructing a VNG station on Shell Oil's property in Waltham (Exh. BGC-38, Sup. Vol. 7, "Special Projects"; Tr. 4, at 63-64). Boston Gas's total share of the cost of this project was $109,778, which the Company booked to Account 386.04 (Other Property on Customers's Premises) (Exh. BGC-38, Supp. Vol. 7, "Special Projects"). The Company closed out this project in January of 1996 (id.). During the hearings, Boston

Gas stated that it has retained this plant in rate base, because Boston Gas uses the facility for Company-owned vehicles (Tr. 21, at 87).

Additionally, during the test year, the Company committed itself to assisting in the construction of a VNG station at Logan Airport as part of a federally-funded project in conjunction with the Commonwealth's Executive Office of Transportation and Construction and other related agencies (Exh. BGC-38, Supp. Vol. 7, "Special Projects"; Tr. 4, at 63-64). This VNG station was to be owned by Alternative Vehicle Services Group ("AVSG") (Exh. BGC-38, Supp. Vol. 7, "Special Projects"). The Company made a capital contribution to AVSG of $195,000, and incurred indirect expenses of $3,094, for a total expenditure of $198,094 which the Company booked to Account 386.04 (id.). The VNG station went into commercial operation on November 29, 1995 (id.). The Company proposed to exclude this investment from rate base, along with $5,656 in accumulated depreciation (RR-AG-59 at 5; Tr. 12, at 10-12; Tr. 21, at 86). None of the parties addressed this issue on brief.

2. Analysis and Findings

a. Standard of Review

The Department has cautioned utility companies that, as they bear the burden of demonstrating the propriety of additions to rate base, failure to provide clear and cohesive reviewable evidence on rate base additions increases the risk to the utility that the Department will disallow these expenditures. Massachusetts Electric Company, D.P.U. 95-40, at 7 (1995); D.P.U. 93-60, at 26; see also, Massachusetts Electric Company v. Department of Public Utilities, 376 Mass. 294, at 304 (1978); Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, at 24 (1967).

With respect to ROR on an investment, the Department has found that a gas utility need not serve new customers in circumstances where the addition of new customers would raise the cost of gas service for existing firm ratepayers. Berkshire Gas Company, D.P.U. 92-210, at 22-23 (1993); Boston Gas Company, D.P.U. 88-67, Phase I at 282-283 (1988). In order to make service to a particular customer economic, the utility may require a CIAC to ensure that existing customers do not incur an undue level of expense for its presence, and that service to the customer is profitable within a reasonable period of time. D.P.U. 88-67, Phase I at 282-283.

The Department has endorsed an analysis of the two basic impacts on existing customers when new customers are connected to the system: (1) the change in gas costs recoverable through the Cost of Gas Adjustment Clause ("CGAC") resulting from the new load and the incremental resource used to serve the new load; and (2) the ROR realized on the incremental rate base required to serve the new customers on the system. D.P.U. 92-210, at 23; Boston Gas Company, D.P.U. 89-180, at 16-17 (1990). The Department has stated that existing customers receive benefits whenever, all other things being equal, the ROR on the incremental rate base exceeds the utility's overall required ROR. D.P.U. 92-210, at 23. Further, the Department has allowed a gas company to include anticipated growth in its estimate of the benefits to be realized on the incremental rate base required to serve the new customers. See Colonial Gas Company, D.P.U. 84-94, at 6 (1984).

In the instant case, the Company presented evidence on its rate base additions as part of its direct case, which facilitated review of approximately 300 significant capital projects that Boston Gas entered into between 1993 and 1995.

b. Revenue Producing Additions

With respect to the Ruggles Center project, the Department recognizes that the building's environmental problems affected the occupancy and gas consumption achieved for the project. If these problems are resolved, it is probable that a tenant will ultimately occupy Ruggles Center and increase gas consumption at the site. The Department finds no evidence that the Company acted imprudently in its decision to enter into the Ruggles Center project. Because the capital costs of the Ruggles Center project were greater than originally estimated, the Department has examined the supporting documentation, including the Street Main Authorization, Distribution Department Estimating Form, and transactions report. It appears from our review that the increased costs are attributable to higher actual overhead costs and additional construction days required. Based on this record, the Department finds that these costs were reasonable and prudently incurred. Accordingly, the Department shall allow this project to remain in rate base.

With respect to the Brighton High School project, the evidence demonstrates that this is a component of a larger project for which future load growth is possible, and that the Company specifically designed this project to allow for future load growth from new customers. The Department finds that the Company acted prudently in commencing the Brighton High School project. Accordingly, the Department shall allow this project to remain in rate base.

With respect to the Wayland Schools project, the evidence demonstrates that the overall project costs, allowing for indirect costs, are consistent with the original estimates. The evidence also demonstrates that the additional load resulting from this project was less than half of that originally anticipated. The Department's review of the supporting

documentation leads us to conclude that the Company acted prudently in estimating the throughput resulting from this project. Accordingly, the Department shall allow this project to remain in rate base.

The Department has examined the supporting documentation for the other revenue-generating projects the Company placed into service between 1993 and 1995. Based on the record, the Department finds that the plant additions that the Company made from 1993 to 1995 are prudent, and are used and useful. Accordingly, the Department finds that inclusion of these additions to the Company's rate base is appropriate.

c. Non-revenue Producing Additions

The Department has examined the rationales and analyses used to support the Company's non-revenue producing plant additions made between 1993 and 1995. Based on the record, the Department finds that these additions made by the Company from 1993 to 1995 are prudent, and are used and useful. Accordingly, the Department finds that inclusion of these additions to the Company's rate base is appropriate.

d. VNG Stations

While the record evidence demonstrates that Boston Gas has an ownership interest in the Waltham VNG station, the evidence demonstrates that the Company's investment at the Logan Airport VNG station constitutes a capital donation to AVSG, and that AVSG owns the property. Therefore, we find that there is no basis for considering Boston Gas to have an ownership interest in the Logan Airport VNG station. D.P.U. 95-118, at 41. See also, NYNEX, D.P.U. 94-50 ("NYNEX"), at 436 (1995). The Department finds that the Company has appropriately excluded its share of this facility from rate base.

C. Communications Equipment

1. Introduction

As of the end of the test year, the Company had an investment of $950,370 in radio equipment in rate base (Exhs. DPU-127; AG-142, at 22, Account 397.02). Although the Company also has equipped its distribution and field workers with cellular telephones which are used to communicate with customers and contractors, the radios are used for communications between crews and the Company (Tr. 16, at 209-210).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that Boston Gas has, in effect, three separate communications systems which duplicate one another (Attorney General Reply Brief at 43). The Attorney General proposes that if the Department allows the Company to include its proposed cellular telephone expense in cost of service, then the Company's radio equipment should be deemed to be no longer used and useful in the provision of service to ratepayers, and should be removed from rate base (Attorney General Brief at 82 n.42, citing D.P.U. 88-67, Phase I at 26; Boston Edison Company, D.P.U. 84-47, at 5 (1985); Attorney General Reply Brief at 43).

b. The Company

Boston Gas argues that the Attorney General has failed to provide any record evidence to support his position that the Company's investment in radio equipment is duplicative (Company Reply Brief at 43). Additionally, the Company maintains that its introduction of cellular phones did not replace any of the existing technology, and that the radios remain in use (id., citing Exh. AG-197).

3. Analysis and Findings

The record in this proceeding indicates that the Company's radio equipment is used by field crews to communicate with a central location on a regular basis, while cellular phones are used to communicate with customers, vendors, and contractors on an as-needed basis. There is insufficient evidence in this record to determine whether Boston Gas's radio equipment is duplicative of its cellular telephones, or whether the Company's cellular phones can meet those communication requirements currently met by radio equipment. See D.P.U. 93-60, at 229. Accordingly, the Department declines to remove the Company's radio equipment from rate base.

D. Cash Working Capital Allowance

1. The Company's Proposal

In its day-to-day operations, the Company requires working capital to pay for its operation and maintenance ("O&M") expenses as well as its purchased gas expenses. Working capital is provided either through funds internally generated by the Company, i.e., retained earnings, or through short-term borrowing. The Department's policy is to permit a company to be reimbursed for the costs associated with the use of its own funds and for the interest expense it incurs for borrowing. Western Massachusetts Electric Company, D.P.U. 87-260, at 22-23 (1988). This reimbursement is accomplished by adding a working capital component to a company's rate base computation.

The Company included a cash working capital allowance of $18,130,470 in its rate base calculation, corresponding to a 42-day cash requirement of $157,562,422 in its non-gas O&M expenses (Exh. BGC-39, at 8).[12] Traditionally, utilities have relied on a 45-day

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12 Purchased gas working capital requirements are recovered through the CGAC.

working capital convention. D.P.U. 88-67, Phase I at 35. The Company proposed a 42-day lag in response to a Department directive in the Company's last rate case to consider and offer an alternative of a period less than the 45-day convention as a means of determining working capital needs (Exh. BGC-38, at 37, citing D.P.U. 93-60, at 50). In the instant proceeding, the Company has utilized a shorter lag, to take into account what it asserts to be a three-day improvement in its meter reading and billing processes achieved as a result of implementing operational changes recommended in its "QUality, Efficiency, Service, and Teamwork" ("QUEST") program (id.; Exh. BGC-156).[13] None of the parties to this proceeding commented on this issue.

2. Analysis and Findings

In Boston Gas's last rate case, the Department emphasized its concern that the 45-day convention for determining a company's working cash capital requirement, which was developed in the early part of this century, no longer provided a reliable measure of a utility's working capital requirements. D.P.U. 93-60, at 50. The Department encouraged utilities to consider and offer cost-effective alternative methods to the 45-day convention that produced lower working capital requirements. Id.

In this case, Boston Gas has proposed a 42-day cash working capital requirement, based on improvements in meter reading and billing processes. The Department finds the Company's proposal and calculation of its cash working capital to be reasonable, and notes that this method results in a lower cash working capital requirement than the 45-day

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13 QUEST is a reengineering effort undertaken by Boston Gas, consisting of a detailed review of the Company's core business practices (Exh. BGC-1, at 20).

convention. Accordingly, the Department accepts the Company's proposed method.[14] Because the Company's working capital allowance must reflect the O&M expense level approved in this Order, the working capital allowance is provided in Schedule 6, below. D.P.U. 94-50, at 309; D.P.U. 92-250, at 244.

III. REVENUES

A. Weather Normalization

1. The Company's Proposal

Boston Gas proposed to increase its test year actual throughput volumes by 130,452 therms and correspondingly increase its test year revenues by $307,889 (Exh. BGC-75, at 3; RR-AG-59, at 11). The Company stated that these adjustments in billing volumes and revenues eliminate the effects of warmer-than-normal or colder-than-normal weather in each month of the test year by using the throughput and associated revenues which would have occurred had the weather been normal (Exh. BGC-75, at 3).

The Company stated that, consistent with the method used in D.P.U. 93-60, it performed its weather normalization adjustments based on a customer-by-customer analysis for all weather sensitive rate classes except G-44 and G-54 (id. at 4).[15] The Company first classified each customer's actual bills into one of 89 pre-determined bill frequency intervals

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[14] Our approval of the 42-day allowance herein does not necessarily signal that a 42-day convention will become Department policy; the Department expects utilities to continue to consider and propose other appropriate alternatives to determine their working capital needs.

[15] The weather normalization adjustments for rate classes G-44 and G-54 are described at the end of this section. The non-weather sensitive rate classes, for which the Company did not perform weather normalization adjustments, are the summer load factor rate classes (G-61, G-62, G-63) and the lighting rate classes (G-7 and G-17) (Exhs. BGC-75, at 4; BGC-97, at 5; AG-19).

for each rate class (id.). Second, the Company split each customer's actual billing use into (1) base load and (2) actual heating use, calculating base load using each customer's summer consumption and setting heating use equal to actual billing use less base load (id.). Third, the Company determined the customer's normal heating use by multiplying the actual heating use by the ratio of normal degree days to actual degree days for the associated billing period (id.). The normal volume for a given billing period is equal to the sum of the customer's base load and normal heating use (id.).

Finally, the Company distributed the normal volumes to the 89 bill frequency intervals and summed the results for each rate class (id.). The Company stated that, by determining the responses of each customer to variations from normal weather on a month-by-month basis during the test year, and by classifying the bills of each customer into one of the 89 bill frequency intervals, it was able to determine if the responses to variations from normal weather occurred in the head block or tail block (id.). In turn, this facilitated the estimation of margin revenues for those rates that have a pricing structure containing head block and tail block charges (id.; Exh. AG-19, at 2).

The Company indicated that it used a different measure of normal effective degree days ("EDDs") from that used in D.P.U. 93-60 (Exh. BGC-97, at 2). Instead of using the 20-year moving average normal EDDs approved in D.P.U. 93-60, the Company used a "smoothing" method for determining normal weather EDDs (id.; Exhs. BGC-75, at 4; BGC-38, at 41; BGC-103; BGC-116). The Company calculated a smoothed normal EDD for a given day by using the minimum and maximum temperatures for that day and the minimum and maximum temperatures for the four days preceding and four days following that given day (Exh. BGC-116, at 2). In effect, this procedure used a total of 360 observations in

calculating the normal EDD for each day of the year (id. at 1-2, Exh. BGC-107 (rev.)).[16] The Company stated that each day's observation in the four-day span is weighted by its distance from the day for which the normal EDD is calculated (Exhs. BGC-116, at 1; BGC-103 (rev.)). The Company added that it used two statistical smoothing computer routines, the Kernel Smoothing and Variable Span Smoothing methods, which provided similar results (Exh. BGC-116, at 3).[17]

Based on the smoothing method, the Company determined that a normal year would have 5,506 EDDs compared to the test year actual of 5,644 EDDs (Exhs. BGC-97, at 2; BGC-99; BGC-101). Based on a 20-year moving average, the Company also calculated 5,521 EDDs representing a normal year's weather (Exhs. BGC-97, at 3; BGC-100). The Company stated that, although the test year was colder than normal based on calendar degree days, the test year peak season was warmer than normal and the off-peak season was colder than normal based on actual billing degree days (RR-DPU-97). The Company added that in determining weather revenue adjustments, it historically has normalized volumes and revenues on a monthly basis (id.). The Company claimed that the impact of the

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16 The Company performed several steps in determining the four-day span before and after a given day. First, the Company assumed that daily temperature is related to temperatures during the past several days (Exh. BGC-116, at 2). Next, the Company estimated an autocorrelation function using lagged (differenced mean) temperature values up to 90 days and plotted the results which indicated a uniformly negative but decreasing magnitudes from three to approximately 18 days lag (id.). The Company stated that a value of nine lag days, less one, divided by two, yielded the four-day span (id.).

17 The Company stated that it ran the smoothing procedure several times to compensate for its "data dithering" procedure, which added a uniformly distributed random variable between -0.499 and 0.499 to the day of the year and to the maximum and minimum temperatures of a given day (Exh. BGC-116, at 3). As reference for its smoothing method, the Company cited: Watson, G.S. (1966), "Smooth Regression Analysis," Sankha, Ser. 425, 359-378 (Exh. BGC-116, Att. 2-3).

warmer-than-normal peak billing degree days was only partially offset by the colder-than-normal off-peak billing degree days (id.). Boston Gas explained that this is the reason its proposed adjustments for both volumes and revenues increase test year levels even though the test year actual calendar year EDDs were greater than the normal calendar year EDDs (id.).

The Company claimed that the smoothing method is more appropriate for rate design purposes because it further reduces the day-to-day variability present in the normal EDDs based on the 20-year moving average, especially in the shoulder months (Exh. BGC-97, at 4; Tr. 6, at 66).[18] In performing its smoothing calculations to determine its proposed normal EDDs, the Company asserted that its "goal of normalizing weather is to minimize or eliminate the effects of medium and short term weather cycles and derive an average long term effect" (Exh. BGC-116, at 1). Accordingly, the Company assumed that annual daily temperatures are influenced by a systematic factor, that occurs every 365.25 days, and a random factor, which is determined by medium and short term cycles (id.).[19] The Company claimed that much of the stability of the smoothing method comes from the use of 360

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18 The differences in total monthly normal EDDs based on the smoothing and the 20-year moving average methods range from zero to six (November) EDDs and the percentage differences range from zero to eight percent (September) (Exh. AG-20). For the annual EDDs, the difference is 15 EDDs and the corresponding percentage difference is 0.272 percent (id.).

19 In developing its proposed smoothed normal EDDs, the Company defined "normal temperature" as "expected temperature" in a probability sense and assumed that expected temperature is "stationary" (Exh. BGC-116, at 1). The assumption that temperature is a "stationary" process means that the expected temperature for a given day in all years is equal (id. Tr. 6, 72-73). The Company added that under the stationary temperature assumption, "if there is a downward or upward trend ... in the data, it is not detectable in the 20 years of data used in this analysis, and is therefore ignored" and that "all local features and peculiarities [e.g., temperature reading from Logan Station] have been smoothed out" (Exh. BGC-116, at 3; RR-DPU-6, at 3). The Company's test for temperature as a stationary process yielded a coefficient of -0.03 with a t value of -2.09 (RR-DPU-6, at 2).

instead of 20 observations in estimating normal EDDs (Exhs. BGC-97, at 4; BGC-103 (rev.); BGC-116).

The Company stated that, because of the increased stability of the smoothed EDDs, the Company need not calculate a new set of normal EDDs as the basis for estimating its weather normalization adjustments in its annual PBR compliance filing (Exhs. BGC-97, at 4; Tr. 6, at 62-63). The Company added that the actual EDDs realized for the period starting 1996 through the end of the five-year term of the PBR plan would not be used in the weather normalization adjustments (Tr. 6, at 62, 74-75). Instead, the Company proposed to use the same 5,506 smoothed normal EDDs for weather normalization adjustments in each year of its price cap compliance filing (id.).

As a basis for comparison, the Company also performed a weather normalization analysis using normal weather based on the 20-year moving average EDDs (Exh. AG-257).[20] Based on this method, the annual total volume adjustment for normal weather is an increase over the test year volume by 1,169,749 therms (id.). The corresponding annual total revenue adjustment is an increase over test year actual margin revenues by $502,531 (id.).

Regarding the weather normalization adjustments for rate classes G-44 and G-54, the Company stated that it used a different method because of some characteristics peculiar to these rate classes, including the timing differences in billings, migration of customers among rate classes, and a limited number of customers that could possibly skew the results if the

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20 The Company stated that the procedures for determining the weather normalization adjustments using the smoothed EDDs and the 20-year moving average EDDs are similar (Exh. AG-19). Differences, however, exist on the magnitude and distribution of normal degree days over the year under the two measures of normal weather (id.).

customer-by-customer analysis were used (Exhs. BGC-75, at 5; AG-19, at 1).[21] The Company first ran statistical models to determine the class's "heating factors" (average change in use per degree day) and the heating factors were applied to the difference between the monthly actual and normal heating degree days to estimate the net volumetric adjustment for normal weather (Exhs. BGC-75, at 5; AG-19, at 1; BGC-107). Next, the Company determined a normal maximum daily contract quantity ("MDCQ") for each rate class for each season (Exh. BGC-75, at 6). The normal MDCQ was estimated by dividing the normal monthly volumes by the average number of billing days in each month and the resulting highest average daily uses for the peak and off-peak seasons were multiplied by 30 (to convert the highest average daily use on an average monthly basis) and divided by 21 to convert to an MDCQ basis (id.). Next, the Company performed the same calculations using actual monthly volumes to determine the actual MDCQ (id.). Finally, the Company took the difference between the normalized MDCQs and the actual MDCQs and multiplied the difference by the effective MDCQ charge resulting in the weather normalization adjustments for rates G-44 and G-45 (id.; Exh. BGC-78).

The Company noted that in D.P.U. 93-60, where the Department approved a similar customer-by-customer method of weather normalization adjustments, the Department expressed concerns regarding the ability to verify the normalization of individual customer bills (Exh. BGC-75, at 6). The Company added that the Department directed the Company, if it "files a similar per customer and bill-by-bill method for weather normalization in its next rate case ... to file an accompanying weather normalization adjustment using the existing rate

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[21] The Company stated that there are a limited number of customers in the existing G-44 and G-54 rate classes (Exhs. BGC-75, at 5; AG-19).

class aggregate method" (id. at 6-7). The Company stated that it performed a statistical study to determine another set of normal volumes and compared those volumes with the normal volumes calculated using its proposed smoothing method (Exhs. BGC-75, at 7; BGC-97). The Company claimed that the difference between the two sets of normal volumes estimated is minimal (Exh. BGC-75, at 7).[22] The Company concluded that the Department's concerns expressed in D.P.U. 93-60, that the bill-by-bill weather normalization may result in skewed or unreviewable results, have been properly addressed (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General opposes the Company's proposal to use smoothed normal degree days as the basis for weather normalization adjustments (Attorney General Brief at 79; Attorney General Reply Brief at 42). The Attorney General contends that the record in this case does not demonstrate whether the Company's proposed smoothing method produces a more accurate revenue requirement or rates than the 20-year moving average method (Attorney General Brief at 79; Attorney General Reply Brief at 42).

The Attorney General claims that the Company's primary purpose in calculating the smoothed normal degree days was to provide a more stable estimate of normal weather that could be used throughout the term of the Company's proposed PBR (Attorney General Brief at 79). The Attorney General asserts that there is nothing in the Company's PBR proposal that requires normal degree days to be held constant and that the Company should be required to normalize its volume throughput and revenues whenever it seeks to increase

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22 The difference between the two sets of normal volumes estimated based on the Company's statistical regression study and its proposed smoothing method is 1,178,413 therms (Exh. BGC-77, at 1).

rates, as it does in any rate case (id.). The Attorney General adds that the Company's proposal to hold the normal degree days constant during the term of the PBR is inconsistent with its proposal to update and incorporate the most recent economic and financial data in its PBR adjustments to base rates (Attorney General Reply Brief at 42).

The Attorney General claims that the 20-year moving average method is a well-tested and accepted basis for weather normalization adjustments, that the method is readily applicable by the Department and all LDCs, that and the method has an added advantage of being simple and easily verifiable (Attorney General Brief at 79). The Attorney General states that this method has been approved repeatedly by the Department (Attorney General Brief at 79, citing D.P.U. 93-60, at 78, D.P.U. 92-210, at 194, D.P.U. 88-67, Phase I at 67-72, Fall River Gas Company, D.P.U. 750, at 8 (1981); Attorney General Reply Brief at 42). The Attorney General urges the Department to reject the Company's proposed smoothing method and direct the Company to use the 20-year moving average method (Attorney General Brief at 79; Attorney General Reply Brief at 42).

The Attorney General claims that by using the 20-year moving average method, the resulting revenue adjustment would be $502,531, or an increase of $194,642 over the adjustment proposed by the Company (Attorney General Brief at 78-79; Attorney General Reply Brief at 42). The Attorney General also claims that the corresponding volume adjustment is 1,169,749 therms, an increase of 1,038,297 therms over the Company's proposed volume adjustment (Attorney General Brief at 79; Attorney General Reply Brief at 42). The Attorney General concludes that the Company should be directed to reduce its revenue deficiency by $194,642 and increase its test year normal throughput volumes by 1,038,297 MMBtu (Attorney General Brief at 79; Attorney General Reply Brief at 42).

b. The Company

The Company claims that its proposed smoothing method reduces variability in the estimated normal weather, throughput volumes and margin revenues, and improves stability for designing rates (Company Brief at 143). The Company notes that increased stability is evident if the estimated degree days are compared on a month-to-month basis, rather than on an annual basis (id. at 144). The Company claims that the Attorney General ignores the importance of such a reduction in monthly variability by focusing on the total annual normal degree days (id.).

The Company asserts that the increased stability gained in using the smoothing method is an important improvement over the 20-year moving average method (id. at 144). The Company reasons that, because of the stability of the smoothed normal degree days, which will not fluctuate significantly with annual updates, the Company need not recalculate the normal degree days in each year of the five-year term of its proposed PBR (id. at 144). The Company stresses that it intends to normalize its billing determinants each year as part of its PBR compliance filing using the 5,506 smoothed normal EDDs (id. at 144-45).

3. Analysis and Findings

The Department standard for weather normalization of test year revenues is well established. See D.P.U. 93-60, at 75-80; D.P.U. 92-210, at 194; D.P.U. 88-67, Phase I at 67-75; D.P.U. 750, at 7-9. In the past, the Department rejected a number of proposals to modify the existing measure of normal weather to account for possible warming trends and improve earnings stability. See D.P.U. 93-60, at 75-78; D.P.U. 92-210, at 194. In rejecting those previous proposals, the Department noted that any evidence of a possible warming trend may only reflect random cyclical changes in weather and that such proposed

redefinitions of normal weather had relatively small impacts on revenues and earnings stability. D.P.U. 92-210, at 194; D.P.U. 93-60, at 78.

The underlying assumption of the Company's smoothing method is that temperature is a "stationary" process. As the Company noted on the record, this assumption ignores any downward or upward trend in weather and assumes that "all local features and peculiarities [e.g., temperature reading from Logan Station] have been smoothed out." (RR-DPU-6, at 3). Although the Department rejected previous proposals to modify the definition of normal weather to account for a possible warming trend, the Department's previous findings reaffirming the use of the 20-year moving average did not necessarily exclude the consideration of any medium-term trends or random cyclical movements in weather that would be captured by using 20 years of temperature data.

The Department has stated, in D.P.U. 750, that the 20-year average degree day data, where possible, should be adjusted "to take into account differences between weather at the measurement station and in the service territory." D.P.U. 750, at 8. However, the record in this case is not clear as to whether the Company's proposed method that smooths out all local features and peculiarities is an adjustment that takes into account the differences between Logan Station and Boston Gas's entire service territory. The Department emphasizes that the primary purpose for weather normalization adjustments is to adjust test year actual volumes and revenues in a manner that reflect normal weather in an LDC's service territory.

The record in the instant case shows that the Company's main reason for proposing the smoothed normal EDDs is to be able to develop a more stable measure of normal weather EDDs that could be used throughout the five-year term of the Company's proposed

PBR. In turn, such a measure of normal weather EDDs would eliminate the need to calculate normal weather EDDs each time the Company makes its annual PBR compliance filing. As noted, the Company intends to submit weather normalization adjustments in its annual PBR compliance filings. Since calculating the 20-year moving average EDDs is a relatively simple process, the Department is not persuaded that any benefits gained by calculating only one set of smoothed normal weather EDDs which would be used for the entire term of the proposed PBR plan, outweigh the minimal efforts that would be expended in calculating annually normal weather EDDs using the 20-year moving average method.

In addition, the Department finds that there is nothing in the Company's PBR proposal that requires normal degree days to be held constant while allowing the Company to update and incorporate the most recent economic and financial data in its annual PBR adjustments to base rates. The Department notes that for ratemaking purposes it is more appropriate to incorporate the most recent weather data in estimating normal weather. Accordingly, the Department reaffirms its long-standing policy to use the 20-year moving average as the measure of normal weather and rejects the Company's proposed smoothing method.

The Department directs the Company in its compliance filing to this Order to revise its weather normalization adjustments using the 20-year moving average EDDs as shown in Exhibit AG-257. The Department directs the Company to reduce its revenue deficiency by $194,642 and accordingly revise its test year normal throughput volumes. In addition, the Department directs the Company in its compliance filing to this Order to provide the monthly and seasonal weather normalization volume and revenue adjustments for each rate class based

on the Company's statistical study filed in this case and consistent with the rate class aggregate method described in D.P.U. 93-60.

B. Billing Day Adjustment

1. Introduction

In its initial filing, the Company proposed an increase of $1,078,640 to adjust for the difference between the number of billing days in the test year and a normal year (Exh. BGC-38, at 11). Because the number of days in the Company's monthly meter reading schedule can vary by billing cycle, the average number of billing days in a given month will not necessarily be equal to the number of calendar days (Exh. BGC-75, at 7). The Company reported that during the test year, it billed customers for 364.0 days of service, but that a normal billing year consists of 365.25 days (id.). During the hearings, Boston Gas revised this adjustment to an increase of $1,006,360 to correct a computational error (RR-AG-59, at 11; Tr. 21, at 88).

To develop its billing day adjustment, Boston Gas first developed a baseload component by multiplying the billing day difference, 1.25 days, by August base use per day of 50.505 billion British Thermal Units ("BBtu"), resulting in a baseload use of 63 BBtu (id. at 8; Exh. DPU-71). To develop the heating component, the Company multiplied the average daily degree days for January 1995, and December 1995, 28.55, by the average heating increment (actual monthly use less August baseload use) during the same period of 8.368 BBtu, to derive an average daily heating use of 238.91 BBtu (Exhs. BGC-75, at 8; DPU-71; RR-AG-59, at 12). Next, the Company multiplied the average daily heating use by the difference between the actual billing days and normal billing days, or 1.25, to develop a total heating use of 299 BBtu (Exh. BGC-7; RR-AG-59, at 12). The sum of the heating use

and baseload use, 362 BBtu, was multiplied by the average gross margin per MMBtu of $2.78 to derive the billing day adjustment of $1,006,360 (Exhs. BGC-79; DPU-158; RR-AG-59, at 12). None of the parties commented on this issue.

2. Analysis and Findings

In the Company's previous rate case, the Department noted its concern over the Company's exclusive reliance on a single month's data to develop the heating increment, and its use of sendout to derive the billing day adjustment. D.P.U. 93-60, at 83. In this proceeding, the Company used an average of January and December data, the beginning and ending of the test year, to derive the heating increment. Additionally, Boston Gas used sales instead of sendout volume to calculate the billing day adjustment. The Department's Order in D.P.U. 93-60 indicated that these two modifications would be appropriate. The Department has reviewed the Company's calculations and assumptions, and finds that the Company has addressed our concerns raised in D.P.U. 93-60. Accordingly, the Department accepts the Company's billing day adjustment.

IV. EXPENSES

A. Employee Compensation

1. Introduction

The Company stated that its total compensation costs compare favorably with other New England utilities and with businesses that operate in its service territory with whom Boston Gas competes for similarly skilled employees (Exh. BGC-38, at 20). In support of this assertion, the Company submitted the following comparisons: (1) wages, salaries and benefits (i.e., compensation) for eleven New England utilities using 1994 Uniform Statistical Reports (Exh. BGC-46); (2) compensation paid by other large urban utilities (Exh. BGC-48);

(3) the percentage of benefits to total compensation for 500 companies provided by the Saratoga Institute (id.); (4) the percentage of benefits to total compensation for nine utilities and six non-utilities by Hewitt Associates (Exh. BGC-49); (5) salaries for 21 management and non-management positions for four utilities and 25 non-utilities (Exh. BGC-47); and (6) a history of the Company's salary and wage increases from 1987 through 1996 for management and union personnel (Exh. BGC-50). Regarding productivity comparisons, Boston Gas submitted three analyses: (1) a study that measures the number of customers per employee and the amount of throughput per employee (Exh. BGC-51); (2) a study prepared by Christensen Associates describing the Company's cost control efforts (Exh. BGC-10); and (3) a statistical benchmarking study comparing gas transportation costs to a sample of national utilities (Exh. BGC-13).

Although employee compensation encompasses payroll, bonuses, health care, insurances, pension, and post-retirement benefits other than pension, this section on compensation addresses only (1) payroll (union and nonunion), including overtime, (2) health care, and (3) dental care.

2. Union and Nonunion Salary and Wage Increases

a. The Company's Proposal

During the test year, Boston Gas booked $88,227,988 in salary and wage expense (Exh. BGC-39, at 15). In its filing, the Company proposed an increase of $3,238,983 for salary and wage increases for nonunion and union personnel (id.). First, Boston Gas separated test year payroll into two categories, (1) nonunion, and (2) union (id.). The Company then adjusted for overtime and reduced payroll costs as a result of its QUEST reengineering initiative, as described in Section IV.C, below (id.). Nonunion salaries were

increased by four percent in 1996, while union wages were increased by 4.5 percent in 1996. Adjusted test year nonunion payroll of $27,428,981 was increased by $1,097,159, while adjusted test year union payroll of $59,901,347 was increased by $2,695,561 (id.). Of the total increase of $3,792,720, the Company charged 85.4 percent to O&M expense, for a net adjustment of $3,238,983 (id.). No party addressed the Company's proposed increase to nonunion and union salary and wage expense.

b. Analysis and Findings

In deciding the propriety of prospective nonunion wage adjustments, the Department applies a three-part standard. D.P.U. 95-40, at 21; Fitchburg Electric and Gas Company, D.P.U. 1270/1414, at 14 (1983). To meet this standard, a company has the burden of demonstrating (1) an express commitment by management to grant the increase, (2) an historical correlation between union and nonunion raises, and (3) an amount of increase that is reasonable. D.P.U. 95-40, at 21; D.P.U. 1270/1414, at 14. Regarding the requirement to demonstrate management's commitment to grant the increases, the increase was approved by Company management effective January 1, 1996 (Exh. BGC-38, at 47; Tr. 11, at 109). Therefore, the Department finds that the Company has an express commitment. Regarding the requirement to establish an historical correlation between union and nonunion annual payroll increase, the Company submitted a comparison of the annual payroll increase for its management and union employees over the previous ten years (Exh. BGC-50). The Department finds that this comparison provides sufficient demonstration of the historical correlation between union and nonunion payroll annual increases. The Department addresses the reasonableness of the Company's nonunion payroll expense in Section IV.A.6, below.

The Department's standard for union payroll adjustments requires that three conditions be met: (1) the proposed increase must take effect before the midpoint of the rate year; (2) the proposed increase must be known and measurable, i.e., based on signed contracts between the unions and the company; and (3) the proposed increase must be demonstrated to be reasonable. D.P.U. 95-40, at 20 (1995). The record shows that the Company's proposed adjustments include only those increases that will be granted before the midpoint of the rate year (Exh. BGC-39, at 15). Accordingly, the Department finds that the Company has satisfied the first requirement listed above. Regarding the requirement that the proposed increases be known and measurable, we note that the increases are based on collective bargaining agreements the Company entered into in 1993 that are still in effect (Exhs. BGC-38, at 47; BGC-52). Accordingly, the Department finds that the Company has satisfied the second requirement listed above. The Department addresses the reasonableness of the Company's union payroll expense in Section IV.A.6, below.

3. Overtime Adjustment

a. The Company's Proposal

The Company proposed to increase its test year salary and wages by $2,516,842 to reflect the Company's most recent five-year average overtime hours per employee (Exh. BGC-39, at 16). The Company reasoned that it used the five-year average value because test year overtime hours were below average due to a warmer than average heating season in 1994/1995[23] (Exh. BGC-38, at 48).

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[23] According to the Company, the fourth quarter of 1994 and the first quarter of 1995 were abnormally warm, 18 percent and four percent warmer than normal, respectively (Company Brief at 119-120).

b. Positions of the Parties

i. Attorney General

The Attorney General urges the Department to reject the Company's $2,516,842 five-year average overtime adjustment on the grounds that it is based on unfounded speculation (Attorney General Brief at 75). Moreover, the Attorney General argues that the Company has failed to provide any direct evidence or analysis to support its contention that the weather during the first quarter of 1995 was the sole reason for the overtime decrease (id. at 74; Attorney General Reply Brief at 35). The Attorney General contends that some of the reduction in overtime hours during the test year can be attributed to QUEST (Attorney General Brief at 75).

ii. The Company

Boston Gas claims that the proposed overtime adjustment more accurately reflects its normalized level of overtime costs (Exh. BGC-38, at 48). The Company disagrees with the Attorney General's argument that some of the reduction in overtime hours is attributable to QUEST (Company Brief at 120-121; Company Reply Brief at 40). Boston Gas contends that QUEST-related personnel reductions and process changes did not occur until after the conclusion of the Company's 1994/1995 heating season, and, therefore, had no effect on its overtime levels (Company Brief at 121). Boston Gas claims that the adjustment is reasonable to ensure that its rates are compensatory and reflect its level of operations (id. at 121).

c. Analysis and Findings

In Western Massachusetts Electric Company, D.P.U. 84-25 (1984), the Department stated:

> [I]t is more appropriate to use the test year level of overtime and premium wage expense in calculating committed payroll. Our finding is premised on the fact that the Company has failed to demonstrate that the test year level of expense is unrepresentative. Absent showing of distortion in the test year figures, we find that averaging is not appropriate.

D.P.U. 84-25, at 145.

The trend of overtime hours for the Company is downward from 1991-1995, except for 1993. Locals 12003 and 12007 of the United Steelworkers of America were engaged in a labor dispute for a portion of 1993. D.P.U. 93-60, at 131. As a result of the 1993 labor action, overtime figures would be abnormal for that year. Thus, the overtime total in 1993 should not be included.

Since the historic trend is toward lower annual overtime hours, it is impossible for the Department to determine how much of the decrease is simply a continuation of the downward trend, how much is due to the QUEST program, and how much is due to the warmer weather during the 1994/1995 heating season. Accordingly, the Department finds that the Company has not demonstrated that its test year overtime figures are unrepresentative. Therefore, the Department rejects the Company's overtime adjustment of $2,516,842.

4. Health Care Expense

During the test year, the Company booked $7,943,196 in health care expenses (Exh. BGC-39, at 19). The Company proposed a decrease of $235,751 to its test year health care expense (id.). Based on its carriers's[24] announced premium levels for 1996, and also taking into account the reduction in the number of employees due to QUEST, the Company projected health care costs in 1996 to be $7,667,141 (Exhs. BGC-38, at 49-50; BGC-39,

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[24] Boston Gas offers its employees the choice of health care coverage from Pru-Care, Blue Cross/Blue Shield, Harvard/Pilgrim, Central Massachusetts, and Fallon (Exh. AG-187).

at 19). Of the decrease of $276,055, 85.4 percent was charged to O&M expense, for a net decrease of $235,751 (Exh. BGC-39, at 19). No party addressed the Company's proposed adjustment to health care expense.

The Department requires that test year health care expenses and post-test year adjustments be (1) known and measurable and (2) reasonable in amount. D.P.U. 95-40, at 25; North Attleboro Gas Company, D.P.U. 86-86, at 8 (1986). In addition, the Department requires that utilities contain their health care costs. Massachusetts Electric Company, D.P.U. 92-78, at 29 (1992); Nantucket Electric Company, D.P.U. 91-106/138, at 53 (1991). The Company included health care costs for active employees at the end of 1995 based on actual premiums (Exhs. BGC-38, at 49-50; AG-187). Therefore, these costs are known and measurable. The Department addresses the reasonableness of the health care costs in Section IV.A.6, below.

5. Dental Care Expense

Boston Gas provides dental care insurance coverage to employees under an agreement with Delta Dental (Exh. BGC-38, at 50). During the test year, the Company booked $863,405 in dental care costs (Exh. BGC-39, at 20). The Company proposed a decrease of $48,399 to its test year dental expense (id.). Based on the provider's 1996 premium levels, as well as the reduced number of employees resulting from QUEST, the Company projected dental care costs in 1996 to be $806,732 (Exhs. BGC-38, at 50; AG-188). Of the total decrease of $56,673, 85.4 percent was charged to O&M expense for a net decrease of $48,399 (Exh. BGC-39, at 20). No party addressed the Company's proposed adjustment to dental care expense.

The Department's standard for dental care expense is the same as that for health care expense, as set forth above. Similarly, the Company included dental care costs for active employees at the end of 1995 based on actual premiums (Exhs. BGC-38, at 50; AG-188). Therefore, these costs are known and measurable. The Department addresses the reasonableness of the dental care costs in Section IV.A.6, below.

6. Reasonableness of Employee Compensation Expenses

The Department has stated previously that, in determining the reasonableness of a company's employee compensation expenses, we will review the company's overall employee compensation expenses to ensure that its employee compensation decisions result in a minimization of unit-labor costs. Cambridge Electric Light Company, D.P.U. 92-250, at 55 (1993). This approach recognizes that the different components (e.g., wages and benefits) are to some extent, substitutes for each other, and that different combinations of these components may be used to attract and retain employees. Id.

The Department also requires companies to demonstrate that their total unit-labor cost is minimized in a manner that is supported by their overall business strategies. Id. However, the individual components of a company's employee compensation package will be appropriately left to the discretion of a company's management. Id. at 55-56.

To enable the Department to determine the reasonableness of a company's total employee compensation expenses, companies are required to provide comparative analyses of their employee compensation expenses. Id. at 56. Both current total compensation expense levels and proposed increases should be examined in relation to other New England investor-owned utilities and to companies in a utility's service territory which compete for similarly-skilled employees. Id.

In addition, to the extent possible, companies are required to provide productivity comparisons (i.e., output per worker-hour, or a similar index). Id. This enables the Department to evaluate whether a higher-cost compensation package is associated with correspondingly higher productivity and value. Id. If this association exists, the resulting unit-labor costs may be minimized, notwithstanding higher compensation, thus benefiting ratepayers. Id.

As stated above, the Company provided all the requisite comparative analyses and their results were taken into consideration by the Company's human resources department when determining the overall nonunion salary increase (Tr. 11, at 110). The outcomes of these analyses demonstrate that, in general, Boston Gas's compensation expenses are comparable to those of other New England utilities and companies in its service territory which compete for similarly-skilled employees (Exhs. BGC-46; BGC-47; BGC-48; BGC-49). While there are some instances where specific personnel positions at Boston Gas are compensated at a higher than the average rate, the Company provided productivity analyses that show that in 1994, customers and throughput per employee were above the average for eight other New England utilities (Exh. BGC-51).

Therefore, the Department finds that the Company has sufficiently demonstrated the reasonableness of its nonunion, union, health care, and dental expenses adjustments. However, regarding salaries and wages, the Department makes three adjustments to the salary and wage adjustment to take the following findings into consideration: (1) the rejection of the Company's proposed overtime adjustment; and (2) the rejection of the December 1, 1996 implementation date for the price cap, thereby increasing the adjustment to include union increases up through May 1997; and (3) the additional QUEST salary and

wage reduction, as ordered by the Department.[25] Because there is no commitment for the nonunion salary increase beyond 1996, no additional adjustment is necessary. Accordingly, the adjustment for nonunion and union personnel is $4,268,182.[26]

B. Self-Insurance Reserves

1. The Company's Proposal

In 1995, the Company changed from a self-insuring to a premium-based plan for both long-term disability insurance and group life insurance (Exh. BGC-38, at 50-51). This change was implemented because the Company's parent company, Eastern, changed to a premium-based plan. Since the long-term disability insurance and group life insurance programs are administered on a corporation-wide basis, Boston Gas changed to a premium-based plan as well (Exh. AG-8). As a result of this change, the Company proposes an increase of $99,857 to its long term disability insurance and an increase of $321,757 to its group life insurance (Exh. BGC-38, at 51-52).

2. Positions of the Parties

a. Attorney General

The Attorney General claims that the Company's excess insurance reserves should be returned to the ratepayers (Attorney General Brief at 80). The Attorney General further

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25 Of the five union contracts, two provide for a 4.5 percent increase until March 1997 and 4.25 percent thereafter, one provides for a 4.5 percent increase until January 1997 and 4.5 percent thereafter, and two provide for a 4.5 percent increase until June 1997 and 4.25 percent thereafter (Exh. BGC-52, Union 12003 Contract at 12, Union 350/343 Contract at 3, Union 313 Contract at 3, Union 444G Contract at 3). For purposes of this calculation, the Department will assume a 4.5 percent increase.

26 Derived by the following equations:
(($27,949,508 - $1,454,030 - $699,528) * .04) + (($60,278,480 - $2,390,752) * .045) + ($60,492,676 * .045 * 6/12) * .854) (RR-AG-5; Exhs. BGC-39, at 15, 19).

claims that the excess reserves amount to $517,848 remaining in the long term disability insurance reserve and $376,370 remaining in the group life insurance reserve (id.). The Attorney General proposes the Company return the total excess of $894,218 to ratepayers using a three-year amortization period (id.; Attorney General Reply Brief at 45).

b. The Company

Boston Gas asserts that the actual amounts of the reserves are smaller than those claimed by the Attorney General (Company Brief at 121). According to the Company, the actual reserves amount to $175,000 for long-term disability insurance and $350,000 for group life insurance (id., citing Tr. 2, at 91). The Company also asserts that the Attorney General is incorrect in his assertion that the ratepayers are entitled to the excess reserves and that the Attorney General's argument is a form of retroactive ratemaking (id. at 121-122).

3. Analysis and Findings

Rates are designed to recover a representative level of a company's revenues and expenses based on an historic test year adjusted for known and measurable changes. See Eastern Edison Company, D.P.U. 1580, at 11-22 (1984). The Company accrued excess reserves prior to the test year because of lower-than-expected payouts. Just as the Department does not permit utilities to reconcile pre-test year expenses in the absence of explicit permission, neither does the Department require a passback of revenues if expenses were lower than those built into rates. See Commonwealth Electric Company, D.P.U. 88-135/151, at 26-27 (1989). The Department finds that the Attorney General's request is an attempt to reconcile pre-test year expenses. Accordingly, the Department rejects the Attorney General's request.

C. QUEST Expenses

1. Introduction

During the test year, Boston Gas booked $6,639,865 associated with its QUEST program (Exh. BGC-39, at 27). The Company stated that the total cost of QUEST was $7,692,839 (id.). This consisted of $3,527,222 in consulting fees and $4,165,617 in early retirement and severance costs (id.). The Company proposed to amortize its total QUEST-related expenses over two years, for an annualized expense of $3,846,420 (id.). Therefore, the Company has proposed a reduction of $2,793,445 ($6,639,865-$3,846,420) to test year cost of service (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that QUEST is "a management tool for repositioning the Company operations to take full advantage of their last days of 'cost of service' regulation while setting the Company on a course to substantial productivity gains" (Attorney General Brief at 31-32). The Attorney General further claims that while ratepayers will pay for the QUEST expenses, shareholders will reap the productivity gains achieved through QUEST in the forthcoming years under the Company's PBR plan (id. at 32). The Attorney General claims that shareholders are, by far, the primary beneficiaries of the QUEST reports presented by the management consultants to Company executives, since these reports focus on business growth and development and not on service quality (id. at 38). The Attorney General argues that since shareholders benefit the most from the work of the management consultants, shareholders should bear their fair share of the QUEST consulting costs of $3,527,222 (id.; Attorney General Reply Brief at 18).

The Attorney General also contends that the amortization period proposed by the Company is unjustified, since the costs of a program should be spread out over the expected life of the benefits (Attorney General Brief at 40). The Attorney General claims that the benefits of QUEST to the Company will continue at least through the period of the proposed price cap plan (id.). Therefore, the Attorney General proposes that the amortization period be extended to five years, consistent with the five-year term of the price cap plan (id.; Attorney General Reply Brief at 20).

b. DOER

According to DOER, since the prospective benefits of QUEST will not be shared by ratepayers, the Department should consider whether it is appropriate for ratepayers to bear all the costs of QUEST (DOER Brief at 10). DOER also suggests that since the benefits from QUEST will accrue throughout the term of the proposed price cap plan, the Department should amortize the costs associated with QUEST over the five-year term of the plan (id.).

c. Bay State

Bay State asserts that Boston Gas should be allowed to amortize the QUEST expenses over two years (Bay State Brief at 3). Bay State contends that the Department must allow the amortization in order to be consistent with past Department rulings (id. at 2, citing NYNEX; D.P.U. 92-210).

d. The Company

According to the Company, the goals of QUEST were to enhance business opportunities, lower costs and improve service to customers by (1) streamlining work methods that add value, (2) eliminating tasks that do not add value, and (3) making employee jobs more efficient and easier to perform (Exh. BGC-38, at 24). The Company stated that

the objective of QUEST was to "see if [the Company] could adapt new ways of managing large organizations to the gas company and make it a more effective provider of services to its customers" (Tr. 1, at 37). The Company stated that among the results of this initiative are organizational and work process improvements that Boston Gas anticipates will increase efficiency significantly and reduce costs of installing new mains and services, and maintaining the distribution system (id. at 21).

Boston Gas further indicated that in addition to those technology initiatives adopted, several internal process changes were made as a result of QUEST (Exh. BGC-16, at 5). By way of example, the Company stated that it is streamlining the new service line quotation process to reduce the time it takes to prepare a quote for a new service line from, in some cases, three to four weeks to a few hours, and to no more than 48 hours for most requests (id.). Boston Gas also has provided cellular phones for its service representatives to call ahead to confirm scheduled service calls (id.; Tr. 16, at 209-210). In addition, Boston Gas has increased its reliance on its AMR vans for initial and final meter readings to reduce the need for customers to be on site for initial and final bill meter reads. According to Boston Gas, this increased use of the AMR vans has improved its billing accuracy by more than doubling the number of remote reads from 33,600 reads in 1995 to 70,400 projected reads in 1996 (Exh. BGC-16, at 5). The Company has also created Emergency Response Units ("ERUs") to enhance emergency response efforts without disrupting routine service calls, provided technical training for field service personnel so they can perform a wider range of duties when on site at a customer's premises, and improved its community communication efforts associated with construction projects (id.).

The Company stated that the QUEST expenses related to early retirement and severance costs are attributed to the scheduled elimination of 161 positions (Exh. BGC-38, at 25). Of these 161 positions, the Company has reflected in the cost of service the elimination of 109 positions; the remaining 52 positions will be eliminated in 1996 and 1997 (id. at 25-27; RR-AG-59, at 17).

The Company maintains that the consultant costs should be included in the Company's cost of service since ratepayers will receive annual benefits of $6,877,804 after a one-time QUEST program cost of $7,692,839 (Company Brief at 97; Company Reply Brief at 33-35). The Company claims that these costs were necessary and prudent and resulted in both economic benefits and service quality improvements to ratepayers (Company Brief at 97-101; Company Reply Brief at 35). Boston Gas asserts that in prior instances of utility reengineering efforts, the Department has allowed for the full recovery of the costs associated with those efforts (Company Brief at 100-101, citing D.P.U. 92-210, at 108; NYNEX at 323-324).

The Company also claims that the Department's two year amortization period approved in NYNEX is appropriate to determine the Company's amortization period (Company Brief at 101). The Company claims that there is a conflict between the Attorney General's assertion that the amortization period should match the time period during which the associated benefits will be recovered, and NYNEX which created an exception to that principle (id. at 101-102). The Company claims that unbundling, increased competition, PBR and the potential for consolidation in the gas industry are similar to those changes that were referenced in NYNEX (id. at 102-103). In addition, the Company argues that it is appropriate for the Department to use the same standard in the instant case (id. at 102-103).

3. Analysis and Findings

The Department has found that denying recovery of expenses associated with cost containment efforts results in a disincentive for utilities to take appropriate actions to control costs and thereby benefit ratepayers. NYNEX at 323-24; D.P.U. 92-210, at 108. The Company has demonstrated that ratepayers benefit from the QUEST program through annual savings accrued by the Company, and through the anticipated improvement to customer service due to operational changes that the Company has implemented. Accordingly, the Department finds that the Company is entitled to recover the QUEST expenses.

Regarding the Attorney General's argument that the Company should bear the consulting cost component of the QUEST program costs, the Department has reviewed certain types of costs to determine whether such should be included as a component of a larger expense category. D.P.U. 92-250, at 102. As in D.P.U. 92-250, we find that the consulting costs related to QUEST are a valid component of the Company's reengineering efforts and should not be separated from the rest of the QUEST expenses. Therefore, the Department rejects the Attorney General's request to exclude the consulting costs related to the QUEST expenses from the Company's cost of service.

Regarding the proposed amortization period for the recovery of QUEST expenses, the Department has found that an unduly short amortization period for such items as technological improvements would be inappropriate because it would shift a disproportionate amount of the costs of these projects to current customers. Boston Gas Company, D.P.U. 93-60-D at 4 (1994). The two-year amortization approved in NYNEX was predicated on the rate of technological change and the development of competition in the telecommunications industry. NYNEX at 324. Conversely, gas distribution utilities are not

currently subject to the same pace of technological innovation or competition. In addition, the record shows that savings resulting from QUEST, in particular those stemming from the early retirement initiative, are "annually recurring savings" (Tr. 21, at 122). Accordingly, the Department finds that the benefits of the QUEST program will last well beyond the Company's proposed two-year amortization. Accordingly, the Company shall amortize its QUEST expenses over a five-year period to match the period of the price cap plan approved herein.

Applying an amortization period of five years to total QUEST expenses of $7,692,839 results in an annual expense of $1,538,568, for a decrease to test year cost of service of $5,101,297. Because the Company has already proposed a reduction of $2,793,445, the Company's proposed cost of service shall be reduced by an additional $2,307,852.

D. QUEST Program Savings

1. Introduction

Boston Gas included a downward adjustment of $3,283,444 to its cost of service to account for salary and wage savings related to its QUEST initiative (Exh. BGC-39, at 17). The Company indicated that 53 nonunion and 56 union positions, totalling 109, have been or are anticipated to be eliminated as a result of the QUEST initiative (id.). Boston Gas multiplied each number of eliminated positions by the average salary for nonunion and union personnel of $58,284 and $42,692, respectively. The total of $5,479,804, minus $1,635,022 in savings realized and included in the test year cost of service, resulted in an adjustment for additional labor cost savings of $3,283,444 (id.).

The Company indicated that it has experienced additional savings associated with improvements achieved through QUEST initiatives that have been incorporated in this filing:

(1) $428,000 in health care, long-term disability insurance, and group life insurance expenses due to the reduction in employees (Tr. 21, at 139); (2) $490,000 in unemployment and FICA taxes due to the reduction in employees (id. at 139-140); (3) $160,000 in revenue enhancement (id. at 140); (4) $184,000 in cash working capital in the rate base calculation due to an improvement in meter reading and billing processes (Exhs. BGC-38, at 37-38; BGC-39, at 8; Tr. 21, at 138); and (5) $136,000 in materials and supplies in the rate base calculation due to improved inventory control measures (Exh. BGC-38, at 38; Tr. 21, at 137). The Company did not propose to include savings associated with the salaries of 22 of the employees who accepted its early retirement offer, but whose positions need to be refilled. Boston Gas stated that it has filled ten of those positions as of July 24, 1996, and is in the process of refilling the remaining positions (Exh. BGC-38, at 29; RR-AG-2).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company understated the savings in salaries and wages associated with QUEST for two reasons: (1) the Company incorrectly reduced the total QUEST savings by the amount of test year savings; and (2) Boston Gas prematurely added back the salaries of employees that it plans to, but has not yet rehired (Attorney General Brief at 38-40).

First, according to the Attorney General, the Company's proposal does not comply with Department precedent that requires that both test year and post-test year savings be factored into cost of service and used to reduce implementation costs of new programs (id.

at 38, citing D.P.U. 92-78, at 47-48 n.37). Therefore, the Attorney General recommends that savings in salaries and wages associated with QUEST be $4,679,526 (id. at 39).[27]

Second, the Attorney General argues that the savings resulting from the employee "oversubscription" which occurred in 1995, and the savings the Company is currently experiencing as a result of not refilling the positions during 1996 must be used to reduce the cost of the QUEST program (id. at 39-40). The Attorney General contends that the fact that these positions have remained unfilled throughout both the Company's heating season and its reengineering initiative demonstrates that these positions are not needed (id. at 77). According to the Attorney General, Department precedent sets company employee levels at test year-end levels based upon the principle that the test year-end level is representative (Attorney General Reply Brief at 34, citing Massachusetts Electric Company, D.P.U. 89-194/195, at 19 (1990); Nantucket Electric Company, D.P.U. 88-161/168, at 66 (1989)). The Attorney General argues that the Company has provided no reason to deviate from this precedent. Accordingly, the Attorney General recommends that the Company's salaries and wages adjustment, along with severance, and enhanced retirement expenses should be reduced by $950,000 (Attorney General Reply Brief at 34-35).

b. DOER

According to the DOER, the Company's cost of service should be adjusted to reflect remaining unfilled positions (DOER Brief at 9).

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27 This amount is derived by multiplying 1995 and 1996 savings of $5,479,804 by 85.4 percent charged to O&M expense (Exh. BGC-39, at 17).

c. The Company

In response to the Attorney General's first argument, Boston Gas points out that the Company and the Attorney General agree that the total annualized wage and salary savings attributable to QUEST are $5,479,804 (Company Brief at 103). However, according to Boston Gas, the Attorney General misunderstood the nature of the Company's adjustment (id.). Boston Gas maintains that it correctly annualized the total QUEST savings by crediting the cost of service with an additional $3,844,782 in wage and salary savings above the $1,635,022 already achieved and reflected in the test year (id. at 104). Accordingly, the Company argues that the Attorney General's recommendation should be denied (id.).

Regarding the Attorney General's second argument, Boston Gas contends that although its 1995 early retirement program was "oversubscribed" by 22 employees and that the payroll reductions associated with these positions are not included in the calculation of QUEST savings, these positions are required in the Company's ongoing operations and either have been filled[28] or are in the process of being filled (id., citing Exh. BGC-38, at 29). The Company also disputes the amount of savings referenced by the Attorney General, and claims that the correct amount is $597,397 based on the average salary of the positions which were eliminated[29] (Company Brief at 105, citing Exh. BGC-39, at 17, ln. 2). Finally, Boston Gas argues that duties associated with the unfilled positions are currently performed by consultants (Company Brief at 106). The Company contends that the early retirement program with the resultant excess vacant positions is not an annually recurring event and

28 Ten positions have been filled as of July 24, 1996 (RR-AG-2).

29 The Company calculated this by multiplying the average salary of the positions actually eliminated of $58,294 by the twelve open positions and the percent charged to O&M expense (Company Brief at 105 n.36).

should be considered outside the normal ebb and flow of employee levels (Company Reply Brief at 36). Therefore, the Company maintains that the Attorney General's recommendation should be rejected (Company Brief at 106).

3. Analysis and Findings

Regarding the Attorney General's first argument that the Company incorrectly reduced the total QUEST-related salary and wage savings by the amount of test-year savings, the amount of recurring savings of $5,479,804 is reflected by including a test year amount of $1,635,022 and an additional reduction to the cost of service of $3,844,782 (multiplied by 85.4 percent charged to O&M expense). Therefore, the Department finds that the Company's calculation correctly accounted for its proposed level of these savings in terms of the calculation method.

Regarding the Attorney General's second argument that Boston Gas prematurely added back the salaries of employees that it plans to, but has not yet rehired, two precedents apply here. First, the Department previously has found that improvements in technology and productivity that may be reasonably anticipated between the test year and the rate year, and which demonstrate a decrease in residual O&M expenses at known and measurable amounts, should be taken into consideration in setting rates. D.P.U. 92-78, at 47-48; Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80, Phase I at 160 (1991).

The savings associated with employees who accepted early retirement is not only reasonably anticipated, but actually occurred. Regardless of the fact that some positions require refilling, the Company included the severance costs associated with those positions in the cost of QUEST, which will be borne by ratepayers. It is also not clear when the Company will complete its rehiring effort, or if the costs associated with employing

consultants to perform the duties of the unfilled positions are in the cost of service.

Second, the Department previously has found that the test year levels generally capture the impact of the normal ebb and flow of employment levels on the payroll expense. D.P.U. 89-194/195, at 19; D.P.U. 88-161/168, at 66. The Department sees no reason to deviate from this standard except to allow the inclusion in the employee level of the ten rehired positions. Accordingly, the Department increases the salary and wage savings associated with QUEST by $597,397.[30,31] In addition, since benefits are 23 percent of an employee's salary, the Department reduces the benefits associated with these employees by $137,400.[32] Finally, FICA tax expense shall be reduced by $53,514,[33] state unemployment tax expense shall be reduced by $7,128,[34] and federal unemployment tax expense shall be reduced by $672.[35]

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30 This number is derived by the equation (12 * $58,294 * 85.4 percent) (Exh. BGC-39, at 17).

31 Although the Department agrees with the Attorney General's position, the Department does not accept his calculation. No party disputed, and the Department accepts, the use of average salaries to compute the QUEST salary and wage savings (Exh. BGC-39, at 17). Therefore, in order to be consistent with that calculation, we calculate the additional savings for the unfilled positions in the same manner.

32 This is derived by the equation (12 * $58,294 * 23 percent * 85.4 percent) (Exh. BGC-38, at 21; RR-AG-2; Tr. 11, at 73-76; Attorney General Reply Brief at App. I).

33 This is derived by the equation (12 * $58,294 * 7.65 percent) (Tr. 11, at 75-76; Attorney General Reply Brief at App. I).

34 This is derived by the equation (12 * $10,800 * 5.50 percent) (Tr. 11, at 75-76; Attorney General Reply Brief at App. I).

35 This is derived by the equation (12 * $7,000 * 0.80 percent) (Tr. 11, at 75-76; Attorney General Reply Brief at App. I).

E. Advertising Expense

1. Introduction

During the test year, Boston Gas booked $1,551,358 in direct advertising expense (Exh. BGC-59). This consisted of: (1) $447,661 in newspaper advertising; (2) $223,384 in radio advertising; (3) $284,748 in print advertising; (4) $33,246 associated with Algonquin's Cooperative Advertising Program; (5) $67,429 in VNG advertising; and (6) $494,890 in direct mailings (id.; Exh. AG-10 [1995 D.P.U. Annual Return] at 80B). In addition, the Company booked $244,366 in agency fees and $38,016 in supervision, for a total of $282,382 in indirect charges (Exh. BGC-59).

The Company stated that, in accordance with the standards set forth in D.P.U. 93-60 and Bay State Gas Company, D.P.U. 92-111 (1992), it reviewed its advertising and determined that $10,613 in advertising expense was image-related (Exhs. BGC-38, at 54; BGC-60; Tr. 4, at 71-72) The Company removed the cost of these advertisements from cost of service (Exh. BGC-38, at 55). Boston Gas included the remaining $1,540,745 in direct advertising expense, as well as the entire balance of its agency fees and supervision costs, in cost of service (id. at 55-57).

2. Positions of the Parties

a. DOER

DOER contends that the Company has included in cost of service $67,429 in VNG-related advertising (DOER Brief at 11, citing Exh. BGC-59). According to DOER, because the Company intends to retain all the benefits of its VNG program, these costs also should be excluded from cost of service (id. at 11-12). Furthermore, DOER argues that the Company has failed to demonstrate that its proposed inclusion of VNG-related expenses in

cost of service provides net benefits to ratepayers, as required by D.P.U. 92-230, at 46-47 (id. at 12). In addition to direct advertising expenditures, DOER proposes that a portion of the Company's indirect advertising costs should be excluded from cost of service (id. at 11-12).

b. The Company

Boston Gas contends that the VNG advertisements should be retained in cost of service, because they serve a dual purpose (Company Brief at 123). The Company argues that the advertisements both promote the use of natural gas vehicles and the environmental advantages of natural gas (id., citing Exh. BGC-59). Therefore, Boston Gas concludes that the advertisements qualify for inclusion in cost of service under Department precedent (id. at 123-124, citing D.P.U. 92-111, at 181-196).

3. Analysis and Findings

Pursuant to G.L. c. 164, § 33A, gas or electric companies may not recover from ratepayers direct or indirect expenditures relating, inter alia, to promotional advertising. D.P.U. 93-60, at 158. However, recovery may be allowed for advertising "which informs consumers of any utility on how they can conserve energy, reduce peak demand for energy, or other services, or otherwise use the services of any utility in a cost-effective manner ... and stimulates the use of products or services which are subject to direct competition from products or services of entities not regulated by the [D]epartment or any other government agency." G.L. c. 164, § 33A. With specific reference to VNG-related expenditures, including advertising, the Department has stated its intent to review such expenditures on a case-by-case basis. D.P.U. 92-230, at 46-47.

The Department has encouraged utility companies and other parties to seek cost-effective methods to review advertising expenditures. D.P.U. 93-60, at 161-162; D.P.U. 91-106/138, at 61-62. In order to facilitate our review of utility advertising, the Department has set forth a four-category system which groups advertising by type, and has provided direction as to the ratemaking treatment of advertisements within these groups. D.P.U. 92-111, at 182-191; D.P.U. 90-121, at 130-136.

Boston Gas has categorized its advertising in a manner which allowed the Department and intervenors to review these expenditures in an orderly and efficient manner, as reflected by the relative time spent during hearings on this issue. The Department finds that $10,613 in advertising expense is image-related, and thus warrants exclusion from cost of service. With respect to VNG advertising, the Department has approved Boston Gas's proposal to treat its VNG service as a competitive service to be assigned to the Company's competitive basket. See Section XI.C.3, below. Our review of the Company's VNG advertising leads us to conclude that, while the advertisements indicate the general benefits of natural gas, they are more focused on the increased availability of VNG as a motor fuel. Therefore, the costs associated with VNG activities cannot be reflected in rates to firm ratepayers. Accordingly, the Department finds that an additional $67,429 in direct VNG advertising expense shall be excluded from cost of service.

Consistent with this treatment, the Department shall exclude an additional $12,284 from cost of service to reflect a pro rata portion of VNG advertising to indirect advertising

charges.[36] D.P.U. 93-60, at 165; D.P.U. 92-111, at 195-196. Accordingly, the Company's proposed cost of service shall be reduced by a total of $79,713.

F. Bad Debt Expense

1. The Company's Proposal

In its initial filing, Boston Gas reported that it booked $14,500,000 in bad debt expense (Exh. BGC-39, at 23). During the hearings, the Company revised its test year bad debt expense, reducing the 1995 bad debt expense from $14,500,000 to $13,960,000, which had the effect of increasing the Company's revenue requirement (RR-AG-59, at 23; Tr. 2, at 8-9). The Company explained that the reduction reflected the elimination of $540,000 in bad debt expense that was associated with non-gas accounts (Tr. 15, at 27-28).

The Company calculated its proposed bad debt expense by comparing the bad debt net writeoffs in the years 1993 through 1995 to firm revenues in the years 1992 through 1994 (RR-AG-59, at 23). The resulting bad debt ratio of 2.22 percent was applied to normalized 1995 firm revenues of $627,967,188 (id.).[37] The Company's resulting allowable bad debt expense is $13,940,872 (id.). Therefore, the Company proposed a decrease of $19,128 to test year bad debt expense (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company's calculation of its pro forma bad debt expense does not conform with precedent and should be rejected by the Department

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36 $282,382 indirect costs * ($67,429 VNG advertising expense/$1,551,358 total direct advertising expense).

37 The Company's proposed revenue increase of $23,829,374 is included in the normalized 1995 firm revenues figure (Exh. BGC-38, at 52; RR-AG-59).

(Attorney General Brief at 67). The Attorney General argues that the Company has lagged its revenues one year behind the year of the net writeoffs,[38] which causes a misstatement of the expected writeoffs in the rate year (id. at 68). Furthermore, the Attorney General contends that the fact that the Department approved the same lagged approach in D.P.U. 93-60 cannot be used by the Company as precedent supporting its bad debt expense calculation in this case, because both the language contained in D.P.U. 93-60, and the absence of an express statement or analysis by the Department, indicates that it was neither the intent nor purpose of the Department to approve such a "sea change" in bad debt expense methodology in that case (id. at 68-69). The Attorney General implies that the Department's use of the words "for the corresponding period" in D.P.U. 93-60 was not an explicit recognition of the lagged revenue approach (Attorney General Reply Brief at 39-40). The Attorney General recommends that the Department should use its standard methodology using the three-year average of coincident years of data (Attorney General Brief at 69). The Attorney General calculates the corrected net writeoffs to firm revenues ratio (using the years 1993 through 1995) to be 2.15 percent (id. at 70).

The Attorney General argues that the Department should deny the Company's adjustment of $540,000 to bad debt expense for non-gas services (id.). While the Attorney General agrees that an allocation of bad debt expense to non-gas service is appropriate, he takes issue with the amount that the Company assigned to non-gas service for three reasons (id. at 71).

First, the Attorney General contends that the amount assigned to non-gas service is unsupported on the record (id. at 70-71). According to the Attorney General, the Company's

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[38] The Company's calculations actually lagged the writeoffs, not the revenues.

witness testified that the Company does not keep subaccounts separating gas bad debt from non-gas service bad debt, and that the Company accrues its bad debt expense on the basis of total accounts receivable including both gas distribution and other services (id. at 71). Therefore, the Attorney General maintains that the Company had no support for its allocation of bad debt to non-gas services, and failed to meet its burden of proof regarding this correction (id.; Attorney General Reply Brief at 41). Second, the Attorney General alleges that the assignment is excessive, stating that the amount assigned to non-gas service is more than three times the rate for the gas distribution service, and that the Company failed to explain the difference (Attorney General Brief at 71). Third, in response to the Company's argument that the Attorney General never questioned the assignment to non-gas service on the record, the Attorney General contends that the Company was put on notice that this part of the Company's filing was at issue, and that the Attorney General's recommendation is based on record evidence (Attorney General Reply Brief at 40).

The Attorney General recommends that the Department allocate the $14,500,000 of test year bad debt expense to gas and non-gas services according to the test year revenues associated with each (Attorney General Brief at 71-72). The Attorney General calculates the amount of test year bad debt expense for non-gas services to be $153,565, and for gas services to be $14,344,581 (id. at 72).

Finally, the Attorney General notes that the Company proposes to recover its full test year level of bad debt over the term of the PBR, and makes no adjustment to recognize that its gas cost revenues will, under its proposal to exit the merchant function, be decreasing progressively (id. at 66). The Attorney General states that gas costs are the largest single item in its cost of service, and that these costs will decrease to virtually zero by the year

2001 (id.). Therefore, the Attorney General proposes that the Company should reduce bad debt levels by the amount of gas costs associated with firm sales levels to C&I customers, and that the Company should file a progressive change in its bad debt allowance with its annual PBR filings or PBR compliance filings (id. at 67). In the alternative, the Attorney General recommends that the Company's bad debt allowance should be allocated between its CGAC and base rates, so that a reduction in yearly levels of gas sales and the level of the CGAC would reflect lower bad debt allowance as customers shift from sales to transportation (id.).

In response to the Company's arguments that allocation of bad debt expense between base rates and the CGAC is problematic, the Attorney General contends that even though the exact rate of migration of customers to transportation service cannot be determined, some allocation of bad debt between base rates and the CGAC should be made as a result of the migration of customers (Attorney General Reply Brief at 38). Second, the Attorney General maintains that although not all suppliers will seek out those customers primarily responsible for the Company's bad debt levels, those customers will have incentives to seek out alternative suppliers, and will therefore not necessarily remain with the Company (id.). Third, the Attorney General contends that though the Company claims that it would be extremely difficult to separate bad debts between gas costs and distribution costs, the Company is currently proposing to unbundle its rates and it would be consistent with this unbundling to separate bad debts between gas costs and distribution costs (id. at 38-39).

b. DOER

DOER claims that as Boston Gas customers migrate to alternative suppliers as a response to retail choice, the Company will no longer incur bad debt expense associated with

gas costs for these customers (DOER Brief at 12). DOER recommends that, in order to ensure that the Company's "cast-off" rates do not permit overrecovery of bad debt expense for the duration of the PBR, the Department should segregate bad debt expense associated with base rates and the CGAC and allow for recovery of each in the particular rate element (id. at 12-13; DOER Reply Brief at 2).

c. The Company

The Company argues that it used a lagged revenue methodology in D.P.U. 93-60, that the methodology was closely examined in that rate proceeding, and that the methodology was accepted by the Department (Company Brief at 113-114). The Company interprets the Department's use of the words "for the corresponding period" in D.P.U. 93-60 as an explicit recognition of the lags (id.). Furthermore, the Company argues that the one year lag used by the Company appropriately matches revenues with expenses, as the writeoffs for the years 1993-1995 relate to sales for 1992-1994 (id.; Exh. DPU-111; RR-AG-51). The Company contends that the Attorney General has provided no basis for changing the lagged revenue methodology in this case (Company Reply Brief at 42).

Regarding the Attorney General's claim that the Company's allocation of bad debt to non-gas services was unsupported on the record, the Company claims that the information contained in Exhibit AG-176 supports its allocation (Company Brief at 115-116, citing Exh. AG-176). The Company also states that it maintains subaccounts for reserves for gas and non-gas bad debts, contrary to the assertion of the Attorney General (id., citing Exh. AG-142, at 18). The Company insists that there is no record for the Attorney General's recommended allocation, which should be denied (id. at 116). Finally, in response to the Attorney General's claim that its non-gas allocation is excessive, the Company

explains that a higher proportion of a customer's unpaid balance is attributed to non-gas related billings because of the Company's practice of first applying customer payments to outstanding gas usage account balances rather than applying payments on a pro rata basis (id.).

The Company claims that, in theory, DOER and the Attorney General are correct in that bad debt expense should reflect the migration of customers from firm sales service to firm transportation service, but that implementation of this proposal contains three difficult problems (id. at 111). First, Boston Gas argues that the rate of migration of customers to transportation-only service is unknown at this time (id. at 111-112). Second, the Company maintains that bad debt expense is unlikely to change, because residential customers, who cause the majority of bad debt expense, are likely to remain with the Company since there is no incentive for such customers to migrate to other suppliers (id. at 112). Third, the Company alleges that it would be extremely difficult to separate bad debts between gas costs and distribution costs, because the Company does not currently track billings between base rates and the CGAC, and the existence of different base rate and CGAC factors in the peak and off-peak seasons in addition to sector-specific CGAC factors for residential and C&I customers would further complicate any calculations (id., citing RR-AG-35; Tr. 15, at 30-32). The Company recommends the Department reject the proposals of DOER and the Attorney General (id.).

3. Analysis and Findings

The Department permits companies to include for ratemaking purposes a representative level of uncollectible revenues as an expense in cost of service. D.P.U. 89-114/90-331/91-80, Phase I at 137-140; Commonwealth Gas Company,

D.P.U. 87-122, at 83 (1987). To determine the amount of uncollectibles, a company performs a calculation that includes determining the average of the most recent consecutive three years's net writeoffs, as a percentage of adjusted test year revenues, i.e., the uncollectible ratio. D.P.U. 90-121, at 96-97; D.P.U. 84-25, at 113-114.

Regarding the lagged method used by the Company to determine its uncollectible ratio, the Company indicated that once a customer's account has been finalized, the account is written off to bad debt if not paid after six months of the final billed date (Exh. AG-161). In addition, the Company's witness testified that the accounts written off to bad debt could be twelve to eighteen months or older (Tr. 15, at 30). On this basis, the Department concludes that the Company's revenues do not correspond to its writeoffs in a manner which supports the Company's proposed lagging methodology. Therefore, the Company has not demonstrated that its one-year lag results in a more representative level of uncollectible expense than the Department's historical method of using the most recent consecutive three years's net writeoffs to determine the uncollectible ratio. D.P.U. 89-114/90-331/91-80, Phase I at 139 (1991) (the use of the most recent three years of data available is appropriate). In the past, the Department has disallowed a company's calculation of its uncollectible ratio where the calculation distorts the company's history of uncollectible expense. See Hingham Water Company, D.P.U. 88-170, at 28 (1989). Therefore, the Department will use the net writeoff and firm revenue figures from 1993 through 1995 as provided in Exh. AG-193, and determines that an uncollectible ratio of 2.15 percent is reasonable.[39] Applying the

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[39] The Department notes that in our Order in D.P.U. 93-60, the only issue addressed by the Department concerning uncollectible expense was the Company's inclusion of forecasted gas costs in its normalized test year revenues. D.P.U. 93-60, at 152-154. The Department did not discuss the use of a lagged method to determine the uncollectible ratio.

2.15 percent uncollectible ratio to normalized firm revenues of $601,435,174 results in an uncollectible expense level of $12,930,856. Accordingly, the Department finds that the Company's proposed cost of service shall be decreased by $1,010,016 due to the change in the uncollectible ratio.

Regarding the Company's allocation of $540,000 to non-gas services, the record evidence indicates that the Company maintains a reserve for non-gas bad debt of $540,000 (Exh. AG-176). The Department accepts the Company's calculation of bad debt associated with its non-gas services. Therefore, the Department rejects the Attorney General's recommended adjustment to the Company's allocation to non-gas services.

Regarding the proposals of the Attorney General and DOER that bad debt expense be adjusted to reflect the migration of customers from sales service to transportation service, the Department agrees with the Attorney General and DOER that customers migrating to transportation service will likely cause gas revenues, and thus bad debt expense, to decrease, and that a new method of allocating bad debt expense is required.

The Department concludes that bad debt should be apportioned between base rates and the CGAC in order to reflect properly the effect of customer migration to transportation service on bad debt expense. Allocating bad debt between base rates and the CGAC is also consistent with the Department's goal of rate unbundling. See D.P.U. 93-60, at 412-413. The Department finds that a reasonable allocation of bad debt should be based on the test year normalized non-gas revenues and gas revenues resulting in an allocation of 38 percent of bad debt to base rates, and 62 percent of bad debt to the CGAC.[40] Since the Department

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40 The Company's test year normalized firm revenues are $604,137,814, consisting of $375,202,673 in gas-related revenues and $228,935,141 in non-gas revenues (RR-AG-59, at 2, 23).

has found an allowable bad debt expense level of $12,930,856, the Company's base rates shall incorporate $4,913,725, with the remaining $8,017,131 to be collected in the CGAC. The Company shall reconcile on a semiannual basis the level of bad debt expense collected in the CGAC based on the actual uncollectible expense attributable to gas costs.[41] Therefore, the Company's base rates shall be reduced by a total of $9,027,147. The allocation to base rates will remain fixed for the period of the price cap plan approved herein. The Department directs the Company to file all future CGAC compliance filings consistent with the allocation specified above.

G. Cellular Telephones

1. The Company's Proposal

During the test year, Boston Gas booked $311,521 in customer communication expense for cellular phones (Exh. BGC-39, at 29). The Company proposed a $498,395 increase to its test year cost of service to reflect annualized "customer communications expense" associated with cellular telephones (Exh. BGC-38, at 58; RR-AG-59, at 29).

The Company explained that as a result of recommendations from the QUEST program, cellular phones were distributed to field personnel (Exh. AG-197, at 1; Tr. 15, at 10). The Company indicated that cellular phones are provided to two categories of employees to use as follows: (1) distribution personnel, who call to make their own arrangements for supplies and police details; and (2) field service personnel, who call customers prior to a scheduled service visit to ensure that the customer is at home and to notify the customer of an estimated time of arrival (Exh. AG-197, at 1; Tr. 15, at 13; Tr. 16, at 209).

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[41] The Company continues to have the obligation to minimize bad debt expense.

Boston Gas stated that its use of cellular telephones has greatly expanded, with consequent telephone bill increases, over the levels incurred in 1995 (Exh. BGC-38, at 58). As of the end of the test year, the Company had 586 cellular phones in service (Exh. AG-196; Tr. 21, at 116). The Company indicated that it anticipates the number of cellular phones in use will remain the same over the period of the PBR (Tr. 21, at 117). To calculate its proposed adjustment, the Company determined an average charge for each of its cellular phone suppliers to arrive at a total monthly charge, and then divided that amount by the year-end number of cellular phones, to arrive at a monthly charge per cellular phone (Exh. AG-196; Tr. 21, at 115-116). The Company then annualized the monthly charge to arrive at an annual charge of $809,916 (Exh. AG-196). The proposed adjustment is the difference between the test year and annualized customer communication expense (RR-AG-59, at 29).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should require the Company to reduce its cost of service by its projection of an annualized level of cellular phone usage (Attorney General Brief at 82). The Attorney General maintains that the Company has provided no evidence that test year levels of cellular phone usage are unrepresentative of current Company usage levels (id.). The Attorney General further maintains that the projection of annualized usage levels is speculative, and is not a known or measurable change to test year levels (id.). The Attorney General contends that, without a full year of usage to generate an average year's usage, the proposed normalization may be unrepresentative of cellular phone usage for a full year (Attorney General Reply Brief at 42-43). According to

the Attorney General, the Company's cost of service should be reduced by $498,700 (Attorney General Brief at 82).[42]

b. The Company

The Company claims that use of cellular telephones has allowed field service personnel to be more productive and that the Company is now beginning to see the positive effects of its policy (Tr. 16, at 212). The Company asserts that distribution of cellular telephones to field service personnel has resulted in fewer "can't-get-in" responses (Tr. 16, at 212; RR-DPU-64). In addition, according to the Company, cellular telephone use has increased productivity of its distribution personnel by increasing the number of jobs completed at the start and end of the day, allowing the elimination of Distribution Dispatch including approximately five staff positions, and increasing the span of control (number of bargaining unit employees per supervisor) for field supervisors (RR-DPU-64).

The Company contends that the number of cellular phones increased throughout the test year, and the proposed adjustment to its revenue requirement reflects the annualization of the expenses associated with the test year-end level of 586 cellular phones (Company Brief at 122). According to the Company, because the annualization calculation used the actual average monthly charges per phone, the adjustment is a known and measurable normalization (id.). Boston Gas concludes that the annualized cellular telephone expense is supported by the evidence, is representative of the current expense level, and should be allowed (id. at 122-123).

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42 The Attorney General also asserts that if cellular phones are to displace the need for radio equipment which is currently in the Company's rate base, then the Department should consider removing the radio equipment from rate base because it is no longer used and useful (Attorney General Brief at 82 n.42). See Section II.C for a discussion of this argument.

3. Analysis and Findings

In establishing rates for companies under its jurisdiction, the Department relies on historical test year data, adjusted only for known and measurable changes. D.P.U. 95-118, at 130; D.P.U. 1270/1414, at 20. The selection of an historical twelve-month period of operating data as a basis for setting rates is intended to reflect a representative level of a company's revenues and expenses which, when adjusted for known and measurable changes, will serve as a proxy for future operating results. D.P.U. 95-118, at 130.

Boston Gas has provided evidence that the number of cellular phones increased substantially during the test year. In addition, the record evidence demonstrates that the increase in cellular phone use due to QUEST recommendations reflects a permanent operational change for the Company's field service and distribution personnel. However, the Company's adjustment was based on an average monthly charge for its cellular phones instead of actual phone usage. The Department finds that the proposed adjustment may not be representative of actual cellular phone usage for a full year. Therefore, the Company has failed to demonstrate that its proposed adjustment to cellular phone expense is both known and measurable. D.P.U. 92-78, at 53; Milford Water Company, D.P.U. 92-101, at 45 (1992). Accordingly, the Department rejects the Company's proposed adjustment to cellular phone expense, and shall reduce the Company's proposed cost of service by $498,395.

H. Rate Case/PBR Litigation Expense

1. The Company's Proposal

In its initial filing, Boston Gas stated that it expected to incur $1,725,000 in rate case/PBR litigation expense for the current proceeding (Exh. BGC-38, at 60). The Company stated that this amount includes legal fees, transcripts, expert and consulting fees, legal

advertising, and other related expenses (id.). Boston Gas proposed to amortize this amount over five years, the proposed term of the price cap plan (id.). Because the Company booked $243,557 in rate case expenses during the test year, Boston Gas requested an increase of $101,443 over test year expense (id.). On November 7, 1996, Boston Gas reported that the total rate case/PBR litigation expense associated with this proceeding was $ 1,729,053 (Exh. AG-199, Supp.). As indicated in Section I.B., above, the Company also initially proposed to include $1,000,000 related to customer education as a component of the Company's proposed PBR proceeding expense. This amount was excluded from consideration by the Department's granting of the Attorney General's objection to the inclusion of this amount in the Company's rate case/PBR litigation expense. Hearing Officers's Ruling on Attorney General's Objection at 5 (September 9, 1996). No party commented on the Company's initially filed proposal.

2. Analysis and Findings

The Department's practice in determining the amount of rate case expense to include in rates is to normalize these costs so that a representative annual amount is included in the cost of service. D.P.U. 91-106/138, at 20; Berkshire Gas Company, D.P.U. 1490, at 33-34 (1983). Normalization is not intended to ensure dollar-for-dollar recovery of a particular expense; rather, it is intended to reflect a representative annual level of rate case expense. D.P.U. 91-106/138, at 20.

In accordance with existing precedent, the Department determines the appropriate normalization period for rate case expenses by taking the average of the intervals between the filing dates of a company's last four rate cases, rounded to the nearest whole year. D.P.U. 91-106/138, at 19-20; D.P.U. 1490, at 33-34. In the instant case, Boston Gas has

proposed a normalization period of five years, reflecting the term of the Company's proposed price cap plan. Using Department precedent for rate case expense recovery, the Company would normalize its rate case expense over a three-year period.[43]

Because the Company has proposed to move from cost of service regulation to performance-based regulation, and has argued that the normalization period for this expense be changed, the Department finds it appropriate to reexamine our existing normalization standard. Under performance-based regulation, utilities generally are constrained from filing rate cases for a predetermined period. In contrast, utilities file rate applications under traditional cost of service regulation at their discretion. Boston Edison Company, D.P.U. 1720, Interlocutory Order of January 17, 1984, at 7-11. Thus, in this case, a normalization period based on the intervals between traditional rate filings is no longer appropriate. Where Boston Gas has proposed a price cap plan of five years, normalization of the Company's rate case/PBR expenses over the term of the price cap plan provides a more representative basis for establishing an annual amount to be included in the cost of service for the "cast off" rates.

Based on the foregoing, the Department finds that where the term of an initial price cap plan exceeds the average period between a company's three most recent rate cases, the Department shall employ the term of the price cap plan in establishing a normalization period for rate case expense. Therefore, the Department finds that the Company's proposal to normalize its rate case expenses over the five-year term of the price cap proposal is

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43 The Company's four most recent rate case proceedings were: D.P.U. 88-67, Phase I (1988); D.P.U. 90-17/18/55 (1990); D.P.U. 93-60 (1993); and D.P.U. 96-50 (Phase I) (1996); The differences (2 years + 3 years + 3 years) divided by three and rounded to the nearest whole, result in an amortization period of three years.

reasonable. Accordingly, we find that the Company's recoverable litigation expenses relating to this proceeding amount to $1,729,053, amortized over five years. The Company booked a total of $243,557 during the test year; the appropriate adjustment to test year expense is an increase of $102,254.

The Department has been increasingly concerned with the level of rate case expense among utilities in general, and specifically noted such in the Company's last rate case. D.P.U. 93-60, at 145; See also D.P.U. 92-111, at 208; D.P.U. 92-78, at 58. A certain amount of litigation expenses are properly within management's control. As a result, rate case expense, like any other expenditure, is an area where companies should seek to contain costs. The Department has attempted to evaluate each company's efforts to control costs, such as its use of outside legal and consulting services. If a company does elect to secure outside services, the Department expects a company to engage in a competitive bidding process for these services. If a company forgoes the competitive bidding process, a company must provide adequate justification for its decision to do so. In addition, the Department directs companies to provide invoices for all outside services which document the number of hours billed, the billing rate, and the nature of the services provided. Failure to provide this information could result in the Department's disallowance of all or a portion of rate case expense.

I. Telemetering Expense

The Company included a total of $45,552 in its cost of service as an adjustment which represents annual operating costs associated with the Company's additional investment in telemetering equipment (Exh. BGC-38, at 61; RR-AG-59, at 14). As indicated in Section II.A.1.c, above, the Company has withdrawn its proposed adjustment for 1996

telemetering investments. As a result, the Company also has withdrawn its request for the related telemetering expense adjustment (Company Brief at 140). The Department, therefore, shall reduce the Company's proposed cost of service by a total of $45,552.

J. Pension Expense

1. The Company's Proposal

Boston Gas recorded gross actuarially determined pension costs of $2,776,048 for the test year (Exh. AG-97). The Company recorded a settlement gain on annuity purchases of $429,083 in the test year resulting in net pension cost of $2,346,965 (Exh. DPU-200). In addition, a portion of net pension cost is capitalized annually (id.). Boston Gas included net pension expense in test year cost of service of $2,004,000, or 85.4 percent of the total pension cost (id.). The Company does not propose an adjustment to its test year pension expense.

2. Position of the Company

The Company claims that its pension expense is reasonable because its pension expense is higher for 1996 than in the test year. The Company notes that the Attorney General has questioned the impact of the QUEST personnel reductions on pension expense (Company Brief at 125, citing Tr. 21, at 142). Boston Gas maintains that its 1996 pension cost is $2,900,000 and that it contributed $4,000,000 in September 1996, to fund its pension obligation (Company Brief at 125, citing Exhs. DPU-198, at 6, 12; DPU-215). The Company argues that 1996 pension cost, which is approximately $100,000 more than 1995 cost, reflects a reduced level of employees (id. at 125, citing Exh. DPU-198). Moreover, Boston Gas maintains that all pension calculations make assumptions about termination levels which are subsequently reconciled to the actual activity (id. at 126, citing Tr. 21, at 143).

Therefore, the Company argues that the $2,004,000 pension expense included in the cost of service is appropriate (Company Brief at 126).

3. Analysis and Findings

The Department has stated that it does not endorse any specific method for the calculation of pension expense for ratemaking purposes and that the intricacies of this issue warrant an investigation on a case-by-case basis. D.P.U. 95-118, at 111; D.P.U. 95-40, at 44; D.P.U. 92-78, at 46.

In this case, the Department finds that basing pension expenses on tax deductible contributions provides a reasonable basis for the determination of pension expense for ratemaking purposes. The record indicates that the Company made cash contributions in tax years 1993 and 1995 and that, because of the well-funded nature of the pension plan, no contributions will be allowed for 1996 (Exhs. BGC-165, RR-AG-47). The evidence indicates considerable variation in the annual contribution levels. Also, the contribution for 1995, $6,650,000, includes an additional contribution of $4,000,000 which resulted primarily from a revision to the current liability interest rate used in the determination of the maximum tax deductible contribution amount (Tr. 24, at 41-44). The $6,650,000 is considerably higher than contributions have been in recent years (Exh. BGC-165). Because the selection of a particular interest rate significantly affects the contribution amounts, and because of the variation in annual contribution levels, the Department will determine a representative level of pension expense. The Department will base pension expense on a five-year average, the four years of cash contributions for tax years 1992 through 1995 inclusive and the projected contributions for 1996. Accordingly, the Department will allow $1,540,240 as a

representative level of pension cost,[44] and will replace the actuarially-determined amount of $2,776,048 with this amount. The evidence also indicates that the Company recorded settlement gains on annuity purchase of $429,083 and $679,924 in 1995 and 1993, respectively (Exh. DPU-200). Netting the five year average of settlement gains, $221,801,[45] against the $1,540,240 and allocating 85.4 percent of the remainder to expense produces net allowable annual pension expense of $1,125,947. This results in a decrease of $878,053 to test year pension expense. The Department reiterates that because of the complexities of this issue, we do not endorse any specific method as appropriate for companies to employ and will continue to investigate this issue on a case-by-case basis.

K. Post-Retirement Benefits Other Than Pensions

1. The Company's Proposal

During the test year, the Company was in the third year of a four year phase-in of post-retirement benefits other than pension ("PBOP") expense ordered in D.P.U. 93-60, at 212-215. The Company included $6,605,026 for PBOP expense in the test year cost of service (Exh. AG-100). This amount incorporates two years and two months of the phase-in through December 31, 1995.[46] The Company does not propose an adjustment to its PBOP expense.

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44 ($0 + $1,051,201 + $0 + $6,650,000 + $0)/5 = $1,540,240 (Exhs. BGC-165, AG-47, BGC-172, DPU-200).

45 ($429,083 + $679,924)/5 = $221,801

46 Current rates include the full amount of the third step of the phase-in, but this amount is not reflected in cost of service as presented. The Company includes the remaining ten months of the third step and the fourth step in the development of the price cap revenues (Exh. BGC-6) and in the reconciliation of total revenue requirement to core rate revenue requirement (Exh. BGC-109).

2. Positions of the Parties

a. Attorney General

The Attorney General maintains that the Company's PBOP expense is overstated in two ways (Attorney General Brief at 83). First, the Attorney General claims that the Company failed to have its actuarial analysis adjusted to reflect the lower employee levels associated with the implementation of the QUEST program (id., citing RR-AG-48). Second, the Attorney General claims, the Company's transition obligation is greatly overstated due to the significantly lower medical cost trend rates and the higher returns on trust fund assets that have occurred compared to the estimates used in establishing the original obligation (id. at 83). The Attorney General states that the original obligation is being amortized and fully included in the annual PBOP cost (id.). The Attorney General maintains that these significant differences between the actual and presumed parameters for the PBOP transition obligation have caused a decrease in current and future funding requirements (id.).

The Attorney General contends that because of lower medical cost trends and the reduction in the number of employees related to QUEST, the current tax deductible cash contribution requirement which is the basis for the amount to be included in rates will decrease immediately (Attorney General Reply Brief at 43). The Attorney General claims that while it is true that by changing the cost accrual, the Company's accounting will recognize this change in cost over the ensuing 15 to 20 years, the FAS 106 accrual amount is not the basis for the amount included in rates (id., citing D.P.U. 92-78, at 83). Therefore, the Attorney General argues that the Department should reduce the cost of service to reflect these reductions in costs (id. at 83).

b. The Company

The Company maintains that the full amount of PBOP costs allowed in rates is recorded as an expense on the Company's books and is fully reconcilable (Company Brief at 124, citing Tr. 24, at 50). The Company states that book expense reflects two components, the actuarially-determined net periodic expense and the write-down of the regulatory asset, and that any difference between the periodic expense calculated in D.P.U. 93-60 and the currently determined actuarial amount serves to increase or decrease the write-down of the regulatory asset (id. at 124, citing Tr. 24, at 37). The Company claims that the effect of the QUEST reductions on the net periodic expense will be reflected in the current year's write-down of the regulatory asset (id. at 124, citing Tr. 21, at 145). Boston Gas also contends that any difference between the original assumptions (including medical trend rates and asset returns) and actual experience is reflected in the actuary's calculation of current periodic PBOP expense (id. at 124). Therefore, the Company argues, it would serve no purpose to reduce the current PBOP expense until the regulatory asset has been fully expensed (id. at 124-125).

3. Analysis and Findings

The Company's policy is to match the annual expense amount determined according to the provisions of Financial Accounting Standard 106 ("FAS 106") plus the write down of the regulatory asset with the amount allowed in rates (Exh. BGC-100; Tr. 24, at 37).

The Department continues to have concerns regarding PBOP health care costs as previously stated in D.P.U. 93-60. Several potentially volatile factors, including inflation, discount and investment rates, medical cost predictions, medical trend assumptions, changes

in the methods of providing health care and technological advances, continue to give rise to enormous uncertainties regarding the future level of the Company's PBOP obligation.

In this case, the Department is particularly concerned with the short-term medical trend rates used in the actuarial studies. The Company uses a medical trend rate of eleven percent for 1995, decreasing one percent per year until 2001, when the ultimate trend rate of five percent is reached (Exh. DPU-205). The evidence indicates that a significant change in the rate of increase in medical costs has occurred since the Company originally adopted FAS 106 in 1991 (Exh. BGC-170; RR-DPU-94). In fact, the Company's actuary recognized the downward trend in rates and decreased the medical trend rates used in the current actuarial study as compared to the rates used in the determination of the regulatory asset in 1991 (Exh. DPU-205, at 8; RR-DPU-94). The record indicates that medical cost increases for 1995 and 1996 have been in the two percent to four percent range (Exh. BGC-170).

In order for the Department to evaluate the impact that short-term medical trend rates have on the determination of the Company's PBOP costs, the Department requested the Company to recompute the PBOP costs based on the 1995 actuarial report and using the medical trend rates provided by the Department[47] (Exhs. DPU-216; DPU-217). The Department finds that the results of the calculations in Exhibit DPU-217 are more reflective of short-term medical trend rates and, therefore, provide a more reasonable level of costs upon which to base PBOP expense for ratemaking purposes. The Department will use a

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47 The Department requested that the Company use a medical trend rate of seven percent for the years 1995 through 1999 inclusive. Further, the Department requested that the Company use the same medical trend rates that it used in the original study for the years 2000 and after, and include the latest information available, including the effects of the QUEST program for the years 1996 and thereafter. All other assumptions were to remain the same (Exhs. DPU-216; DPU-217).

five-year average of the total funding amounts shown on Exhibit DPU-217, at 3, for the years 1997 through 2001 inclusive. The Department will include $6,774,709[48] for PBOP expense. This will result in an increase of $169,683 to the cost of service. This is the total amount that the Department will allow for PBOP expense in rates. Therefore, the Department will eliminate the remainder of the FAS 106 phase-in adjustments totaling $2,569,231 as shown, for example, on Exhibits BGC-6, at 1 and BGC-109. The Department finds that all amounts allowed in rates shall be used for pay-as-you-go payments and for tax-deductible contributions made to a trust for PBOP.

L. Quality of Service Penalty

1. Introduction

In Boston Gas's last rate case, the Department expressed concern about the Company's quality of service. D.P.U. 93-60, at 10. The Department recognized that the high percentage of complaint calls from the Company's customers to the Department's Consumer Division, constituted a warning that the Company's quality of service was inadequate.[49] Id. Specifically, Consumer Division statistics on Boston Gas indicated that while the Company served only 41 percent of all gas customers in the Commonwealth, it generated 60 percent of all complaints received concerning LDCs. Id. at 8. The Department

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48 ($8,229,725 + $8,079,795 + $7,935,616 + $7,786,810 + $7,632,624)/5 = $7,932,914 * .854 = $6,774,709.

49 The Consumer Division's data are organized according to utility company, coded according to type of complaint, and tabulated monthly. The majority of the complaints consist of billing, credit and quality of service issues (Exh. AG-112). In disputed billing cases, if the Department determines that a company has violated the Department's regulations concerning consumer protection (220 C.M.R. §§ 25.00 et seq.), the disputed billing amount is abated (see, e.g., Weldon v. Bay State Gas Company, D.P.U. 20064 (1979)).

directed Boston Gas to propose steps to significantly reduce its level of customer complaints. Id. at 10. Furthermore, the Department stated it would continue to monitor the Company's efforts, and, if necessary, investigate its quality of service in the Company's next base-rate proceeding. Id.

2. The Company's Response to D.P.U. 93-60 Directives

In response to the Department's directives, the Company stated that it has made significant progress in the area of customer satisfaction with quality of service, and will make strong efforts to continue that progress (Exh. BGC-16, at 5). Boston Gas stated that it is committed to continuing to provide better customer service in a competitive market through QUEST-related improvements, and seeks to dispel any concern that the Company might attempt to reduce the quality of its customer service in order to boost earnings through its PBR plan (id. at 4).

The Company stated that it also recognized the need for a quantitative evaluation of customer satisfaction to ensure that measures implemented as a result of QUEST were effective (id.). Therefore, in 1992, the Company retained WalkerInformation ("Walker") to conduct an independent survey to determine the overall quality of service of the Company's products and services (id. at 3). Since the completion of the initial Walker survey in the third quarter of 1994, the Company has continued to measure customer satisfaction on a quarterly basis (id. at 8). According to the Company, the Walker survey results for the third quarter of 1995 indicated "very good" or "excellent" ratings from approximately 78 percent of surveyed customers (id. at 6). Boston Gas added that the survey results indicated that the Company's overall service quality has been improving over time on an equivalent quarter-to-quarter comparison, and that its performance is above the national average as

compared to Walker's statistics for its other utility clients (id. at 6, 10). Additionally, the Company has proposed as an element of its price cap plan a Service Quality Index ("SQI") implementation which includes a "one-way" incentive that will penalize the Company up to $1,000,000 if it fails to maintain certain levels of customer service quality (id. at 4-5).

In addition to the measurements provided by the Walker surveys, the Company stated that it has been implementing various service quality improvement technologies through QUEST (id. at 4). The Company maintained that since QUEST was implemented, it has: (1) streamlined the process for providing estimates for the installation of new service lines; (2) provided cellular phones to service representatives to confirm scheduled service calls; (3) increased the use of automated meter reading vans to provide customers with regular, actual meter readings; (4) created emergency response units to enhance the Company's ability to respond promptly and efficiently to both routine and emergency calls; (5) provided technical training to field service personnel to enable them to perform a wider range of duties; and (6) improved communication with customers and non-customers who may be directly affected by Company construction projects (id. at 5).

Boston Gas explained that it has developed a computerized dialing system that allows the Company to contact more delinquent customers (id. at 21). The Company stated that the increase in customer contacts has led to an increase in the number of negotiated agreements with delinquent customers for payment terms, as well as reductions in terminations of service and outstanding receivables, and a corresponding increase in complaints to the Department's Consumer Division (id. at 20-21).

According to the Company, while it is gratified that its complaint level has dropped, it does not believe that the level of the Department's Consumer Division complaints relative

to other utility companies is an accurate measure of the quality of service Boston Gas provides (id. at 20). The Company argued that although two-thirds of all calls and complaints involve billing, credit and collection, Boston Gas's customers also consider customer inquiry functions, and field service to be important in their evaluation of overall quality of service (id.). Additionally, Boston Gas asserted that only one-half of one percent of its total customer base contacts the Department in a given year (id.). Lastly, the Company stated that because it has undertaken a collection effort more comprehensive than that of other Massachusetts LDCs, Boston Gas engages in greater customer contact efforts than other LDCs, and thus experiences a corresponding increase in reported complaints (id.). However, the Company maintained that the benefits of increased customer contact far outweigh the associated "costs" (id.).

3. Positions of the Parties

a. Attorney General

Claiming that Boston Gas still has a quality of service problem, the Attorney General proposes adding $169,606 to the Company's pro forma revenues as a penalty, representing a three-year average bill abatement level (Attorney General Brief at 76; Attorney General Reply Brief at 22). According to the Attorney General, this amount represents revenues the Company would have collected from January 1993 to December 1995, had its quality of service been at a level consistent with Department billing and termination regulations (Attorney General Brief at 76; Attorney General Reply Brief at 22). The Attorney General rejects Boston Gas's assertions that its quality of customer service has steadily improved since its last rate case (Attorney General Brief at 40-41, 76). The Attorney General contends

that Boston Gas's response to the Department's warning in its last rate case was inadequate (id. at 76, citing D.P.U. 93-60).

In an effort to determine the relative performance of the Company in the instant case, the Attorney General compared the quality of customer service statistics generated by the Department's Consumer Division for Boston Gas to those of other jurisdictional LDCs (id. at 76, citing Exh. AG-112). According to the Attorney General, because 58 percent of all customer complaints lodged against the Commonwealth's gas utility companies are from Boston Gas customers, large numbers of adjusted bills are generated due to the Company's "malfeasance" in the area of customer service (Attorney General Reply Brief at 20-21).

Specifically, the Attorney General argues that the number of complaints received by the Consumer Division from Boston Gas's customers is at least the same as, if not greater than, those from customers of other similar and much larger utilities in the Commonwealth (id.). The Attorney General compared Boston Gas to BECo, a utility twice the Company's size, and NYNEX, a state-wide company with approximately 4,037,580 lines[50] (id.). The Attorney General reports that in 1993, Boston Gas's abated billing revenues totaled $154,500, BECo's abatements totaled $159,800, and NYNEX's abatements totaled $40,700 (id.). In 1994, Boston Gas had $279,500 in abatements compared to BECo's $173,800 and NYNEX's $22,800 (id.).

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50 The Attorney General noted that NYNEX had 6,000,000 "lines/customers." According to NYNEX's most recent annual report, the number of lines it owns is 4,037,580; however, NYNEX could not produce an exact figure for the number of customers it serves. (Attorney General Reply Brief at 21, citing Annual Report of New England Telephone and Telegraph Company for the Year Ended December 31, 1995, Table III at 1.2 of 1).

The Attorney General also compared the Company's abatement levels and number of Consumer Division complaints with the next three largest LDCs in the Commonwealth (id.). Combined, Bay State, ComGas and Colonial serve a mixture of older urban and suburban communities with approximately 110,000 customers, 20 percent more than Boston Gas (id. at 21-22). However, the Attorney General claims that the Company's 1995 billing adjustments were 2.25 times the combined total of the billing abatements of the other three LDCs (id. at 22).

In addition to criticizing the Company for its high customer complaint and bill abatement ratios, the Attorney General also is "dubious" about the reliability of the Walker survey information (id. 22 n.17). According to the Attorney General, the Company surveyed a select few of its customers and trade allies (id.). As the Attorney General argues, because the surveys were scripted and conducted by Boston Gas employees and a pollster, they are biased in the Company's favor (id.). Therefore, the Attorney General contends the survey results are of little use in determining how well the Company actually serves its customers (id.). The Attorney General argues that the Company's marketing vice president considered the Walker survey results to be so inconclusive that he elected not to include them in the Company's SQI (id.). Thus, the Attorney General maintains that the Department also should accord little or no weight to the Walker surveys (id.).

b. The Company

The Company contends that it has thoroughly examined the service quality it provides, has determined it to be excellent, and maintains that any fair reading of the Company's service information will confirm this conclusion (Company Brief at 111). The Company points to the number of past improvements made in customer service through

QUEST and the high overall ratings the Company received in the Walker surveys as evidence of its demonstrated commitment to customer service (id. at 106, 107). In addition, the Company emphasizes that it is committed to continuing to improve customer service in the future (id. at 107).

Boston Gas contends that the Attorney General's attack on its quality of service is a result of incorrect, omitted, and misunderstood statistics (Company Reply Brief at 37). In addressing the specific criticisms made by the Attorney General, the Company disputes the Attorney General's characterization of "record billing abatements" made during 1994 (Company Brief at 108). The Company argues that these abatements statistics may represent issues unrelated to the Company's service quality such as reductions in terminations, arrearages and estimated bill complaints, and increases in Company-customer contact producing greater numbers of payment agreements (Company Reply Brief at 38). According to Boston Gas, the Attorney General fails to note that the exhibit upon which he relies shows that (1) the Company's billing adjustments fell by almost 75 percent in the 1995 test period and continued to fall during 1996, as the Company's AMR program reached the 80 percent penetration level; and (2) the redesigned and improved bill format was introduced in 1995 (Company Brief at 108; Company Reply Brief at 38).

The Company also protests the Attorney General's "selective" examination of the Department's Consumer Division statistics for 1994 and 1995 which indicate that the Company generated 65.5 and 56.4 percent of all complaints involving gas companies (Company Brief at 108). The Company contends that the Attorney General purposely fails to include any reference to Consumer Division data for the first five months of 1996 when the Company's complaint level (cases and second referrals) continued to fall to the current level

of 49 percent (id. at 109). In addition, the Company disputes the veracity of the Attorney General's claims that QUEST treats "customer service" as a public relations/marketing problem (id.). Rather, the Company asserts that one of the focal points of QUEST is customer service (id.).

Boston Gas contends there is no compelling reason to impose the Attorney General's proposed quality of service sanction, since complaints, abatements, telephone inquiries terminations and residential arrearage have dropped "precipitously" (id. at 110; Company Reply Brief at 38). The Company notes that the Department has acknowledged that the complaint statistics maintained by the Department's Consumer Division are not conclusive, but may serve as a warning sign of other problems that cannot be disregarded (Company Brief at 110-111, citing D.P.U. 93-60, at 10). However, the Company contends that in this proceeding it has demonstrated its excellent service quality (Company Brief at 111).

4. Analysis and Findings

In the Company's last rate case, the Department criticized the Company for its service quality; however, we recognize the improvement demonstrated by Boston Gas in this area. The Department shares the Attorney General's concern for the maintenance of high quality of service, but the Department finds that the record does not support the Attorney General's assertion that the Company fails to provide good customer service.

Although the number of complaints received by the Department's Consumer Division from Boston Gas customers has been the same as or much greater than those received for the same size and much larger utility companies, the raw number of complaints in and of itself does not necessarily reflect poor quality of service. We agree with the Company that its

increased collection efforts could be contributing to the total number of calls received by the Consumer Division that are tabulated as complaint calls. While the Department recognized in the Company's last rate case that the Consumer Division complaint statistics were too high, we find that since 1994 there has been a fifteen percent drop in the number of Consumer Division complaints concerning Boston Gas.

With respect to the Attorney General's concern regarding the number of abatements given to Boston Gas customers, the evidence in this case shows that the Company has realized a 75 percent drop in billing adjustments in 1995 and a subsequent decrease in 1996. We find that Boston Gas is operating in accordance with the Department's goal of encouraging all utilities to improve their quality of service and thereby reducing the number of abated bills.

The Attorney General has put forth a persuasive argument as to why the Walker surveys should not be accorded much weight. However, because the Department has no means of determining the degree of bias, if any, reflected in the Walker surveys, we shall examine other indicators of Boston Gas's quality of service. We are pleased with the quality of service implementations that the Company has made through QUEST, and further initiatives it plans to undertake to ensure improved quality of service. The Department is encouraged by Boston Gas's improvements such as AMR devices, computerized customer account monitoring, and field communication enhancements which improve the Company's efficiency and overall quality of service.

The Department recommends that all utility companies improve their quality of customer service through measures like QUEST. However, the Department cautions Boston Gas to continue to improve its quality of service after its PBR plan is implemented in order

to ensure that it fulfills its public service obligation. The Department hopes that in addition to its directive, the "one-way" incentive in the Company's PBR plan, which will financially penalize Boston Gas if it fails to reach its customer service objectives, will help ensure that the Company continues to improve its customer service. Accordingly, the Department rejects the Attorney General's proposed quality of service sanction.

M. Accumulated Deficient Deferred Income Taxes

1. Introduction

The Company has incorporated $363,522 for the amortization of deficient deferred income taxes as both a component of its taxable income calculation and its proposed income tax expense(Exh. AG-54; RR-AG-59, at 43). Boston Gas stated that this represents a three-year amortization of its deficient deferred income taxes allowed in D.P.U. 93-60 (Tr. 8, at 128-129). The Company reported that the amortization period would terminate November 1, 1996 (id. at 129).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company should remove $598,139 from its proposed test year cost of service attributable to the amortization (Attorney General Brief at 82). According to the Attorney General, the Company has recovered the full amount of the remaining amortization as of October 31, 1996, and therefore, this amount should not remain as a recurring expense (id. at 81-82). The Attorney General criticizes Boston Gas for seeking the inclusion of this amortization on the supposition that a similar amortizable expense may recur in the future (Attorney General Reply Brief at 33). The Attorney General

disputes the Company's characterization of amortizations of this kind as being part of the natural ebb and flow of recurring expenses (id. at 34).

b. The Company

Boston Gas argues that the amortization of accumulated deferred income taxes should remain in its cost of service because this expense likely will be replaced by other expenses which would be amortized (Company Reply Brief at 40). The Company contends that amortization have ebbs and flows just as do customer base and employee levels (Company Brief at 119). Boston Gas claims that, just as there will be changes in the number of customers it serves, inevitably there will be new circumstances requiring additional amortization expenses, and thus the test year amortization should be retained in cost of service (id.).

3. Analysis and Findings

We find the Company's argument regarding recurring amortizations to be unpersuasive. In essence, Boston Gas is proposing that rates be designed to recover unanticipated, unquantifiable costs based on some probability of future events. Because the Department does not permit a company to accumulate funds for future maintenance through rates, the Department rejects the Company's proposal to maintain a reserve for future amortizations. D.P.U. 95-118, at 122; Grafton Water Company, D.P.U. 18268, at 8 (1975); see also D.P.U. 91-106/138, at 94-97.

Accordingly, the Department has revised the Company's income tax calculation by removing the amortization from both the taxable income calculation and income tax expense. The results are found in Schedule 8 of this Order.

N. SNG Plant Amortization

1. Introduction

During the test year, Boston Gas booked $253,767 of undepreciated expenses relative to its now-retired Everett Synthetic Natural Gas Plant ("SNG Plant") (Exh. AG-10, [1995 D.P.U. Annual Return] at 27). The Company is amortizing this investment pursuant to the Department's Order in D.P.U. 93-60, at 43-44 and D.P.U. 93-60-A at 6-7.

2. Position of the Parties

a. Attorney General

The Attorney General argues that Boston Gas's test year amortization expenses associated with the SNG Plant should not be included in cost of service (Attorney General Brief at 81). The Attorney General asserts that the Company was allowed to collect the undepreciated balance over three years commencing on November 1, 1993, and that the balance will have been fully recovered by the date of this Order (id.).

The Attorney General contends that the Company "misses the mark" and is "reaching" in equating extraordinary amortizations with clearly quantifiable expenses that have "ebbs and flows," such as number of employees and customer base (Attorney General Reply Brief at 33). The Attorney General states that periodically recurring expenses, as he characterizes the SNG Plant, are subject to amortization when they are extraordinary and fall within a test year (id.). According to the Attorney General, the cost of such extraordinary recurring expenses is amortized over the anticipated life of the project (id.). Therefore, as the Company will have recovered its total investment in the SNG Plant prior to the beginning of the rate year, the Attorney General argues that the Department should order the Company

to decrease its cost of service by one-third of the total balance, or $210,451[51] (Attorney General Brief at 81).

b. The Company

Boston Gas disputes the Attorney General's assertion that amortization expenses associated with the SNG Plant should be removed from its cost of service (Company Brief at 119). While the Company does not dispute the fact that the amortization period for the SNG Plant will expire in 1996, it opposes the Attorney General's recommendation (id. at 118). The Company argues that it would be consistent with the Department's policy on the ebb and flow of employee levels and customer base to apply the same treatment to amortization expenses (id.). Boston Gas asserts that, just as there are expenses associated with the amortization of the SNG Plant currently, there will be other expenses of a similar nature in the future, particularly in light of the five-year term of the PBR plan (Company Reply Brief at 40). Therefore, the Company maintains that amortization expenses should be retained in cost of service (id.).

3. Analysis and Findings

We find the Company's argument regarding recurring amortizations to be unpersuasive. The Department had found that the SNG Plant's deactivation during 1992 was an extraordinary event that warranted amortization of the remaining investment. D.P.U. 93-60, at 42-44. In essence, Boston Gas is proposing to design rates to recover unanticipated, unquantifiable costs based on some probability of future events. Because the Department does not permit a company to accumulate funds in advance for future

51 The Attorney General based this amount on the original undepreciated balance of $631,354 associated with the SNG Plant cited in D.P.U. 93-60 (Attorney General Brief at 81). The actual balance was $831,354. D.P.U. 93-60-A at 6.

maintenance through rates, the Department rejects the Company's proposal to maintain a reserve for possible future amortizations. D.P.U. 95-118, at 122; D.P.U. 18268, at 8; see also D.P.U. 91-106/138, at 94-87.

The term for the recovery of the undepreciated balance of the SNG Plant was three years, commencing on November 1, 1993, and terminating on October 31, 1996. Therefore, based on the foregoing, the Department finds that the SNG Plant amortization shall be excluded from the Company's cost of service. Accordingly, the Company's proposed amortization expense shall be reduced by $253,767.

O. Salem LNG Tank Amortization

1. Introduction

During the test year, Boston Gas booked $105,756 in amortization expense associated with repairs made in previous years to its Salem LNG tank (Exh. AG-10 [1995 D.P.U. Annual Return] at 27. Shortly after the tank was completed in 1972, it developed a series of leaks which the Company repaired at a final cost of $1,536,446. D.P.U. 88-67, Phase I at 145. In 1982, the Department permitted the Company to amortize the repair expense over the tank's estimated remaining life of fifteen years. Id. at 143-145; Boston Gas Company, D.P.U. 1100, at 89-90 (1982).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company's test year cost of service includes $149,857 attributed to the amortization of Salem LNG tank repairs approved in D.P.U. 88-67, Phase I. Claiming that the Company has acknowledged that the repair costs will be fully amortized in 1996, the Attorney General argues that the Company's cost of

service should be reduced by $149,857 (Attorney General Brief at 74, citing Exh. AG-142, at 6). The Attorney General assails the Company's "gall" in demanding recovery of expired and expiring amortizations, and contends that the ratemaking principle of "ebb and flow" was not designed to cover "fictitious circumstances" or to serve as a guise for future test year ratemaking (Attorney General Reply Brief, at 33-34).

b. The Company

The Company disputes the Attorney General's claim that the Salem LNG repairs will be fully amortized in 1996. According to Boston Gas, the evidence cited by the Attorney General actually demonstrates that the year-end unamortized balance is $149,857, more than the $105,756 included in cost of service (Company Brief at 117-118, citing Exh. AG-10 [1995 D.P.U. Annual Return] at 27). Therefore, the Company concludes that the amortization will continue into 1997 (id. at 118; Company Reply Brief at 40).

Additionally, Boston Gas maintains that it performs substantial repairs at its three LNG facilities on a periodic basis (Company Brief at 118). The Company contends that repairs of this nature are an ongoing expense, which should be included in cost of service (id.).

3. Analysis and Findings

The record in this proceeding demonstrates that the test year amortization associated with the Salem LNG tank repairs was actually $105,756, and not $149,857 as claimed by the Attorney General. On this basis, the Department finds that the amortization will continue into 1997, and therefore qualifies for inclusion in Boston Gas's cost of service.

We find the Company's argument concerning recurring amortizations to be unpersuasive. The Department deemed the Salem LNG tank repairs to be in the nature of an

extraordinary expense item which warranted amortization. See D.P.U. 1100, at 91. In essence, Boston Gas is proposing that rates be designed to recover unanticipated, unquantifiable costs based on some probability of future events. Because the Department does not permit a company to accumulate funds in advance through rates for future maintenance, the Department rejects the Company's proposal to maintain a reserve for future amortizations. D.P.U. 95-118, at 122; D.P.U. 18268, at 8; see also D.P.U. 91-106/138, at 84-87 (1991).

As of the end of the test year, the Company's remaining unamortized tank repair expense was $149,857 (Exh. AG-10 [1995 D.P.U. Annual Return] at 27). The record evidence demonstrates that of this amount, an additional $96,943 ($105,756 * 11/12) will be amortized by the date of the issuance of this Order. Because only $52,914 ($149,857 - $96,943) will remain unamortized as of December 1, 1996, inclusion of the full test year's amortization of $105,756 in cost of service will result in overrecovery of this expense. Therefore, the Department finds it appropriate to adjust the Company's amortization expense so that only the unamortized balance remains in cost of service.
D.P.U. 89-114/90-\331/91-80, Phase I at 125. Accordingly, the Company's proposed cost of service shall be reduced by $52,842.

P. Depreciation Expense

1. The Company's Proposal

During the test year, Boston Gas booked $33,458,272 in depreciation expense and $5,484,660 in amortization expense (Exh. BGC-39, at 38). In its initial filing, the Company proposed to increase its depreciation expense by $2,736,602 to reflect the following adjustments: (1) an increase of $1,370,039 to annualize the current depreciation accrual

rates on year-end plant investment;[52] (2) an increase of $1,341,077 reflecting the depreciation on 1996 system replacement investments discussed in Section II.A.1.a, above; and (3) an increase of $25,486 reflecting the depreciation on the telemetering equipment discussed in Section II.A.1.c, above (id. at 37).[53] During the hearings, the Company revised this increase to $2,725,291 to eliminate $11,311 in depreciation expense associated with a revised plant in service balance (RR-AG-59, at 38; Tr. 21, at 87).

In its initial filing, the Company proposed to increase its amortization expense by $765,372 to reflect the following adjustments: (1) a decrease of $257,578 associated with the amortization of acquisition premiums; (2) an increase of $95,914 to annualize the amortization of intangible plant; (3) an increase of $559,000 reflecting the amortization of the performance measurement systems discussed in Section II.A.1.b, above; and (4) an increase of $368,036 associated with the amortization of leasehold improvements (id.). During the hearings, the Company revised this increase to $766,372 to reflect revisions to its proposed inclusion in rate base of its performance managment systems (Exh. BGC-39, at 37; RR-AG-59, at 37).

In support of its proposed depreciation accrual rates, the Company is relying on the accrual rates approved by the Department in D.P.U. 93-60, which in turn were based on the depreciation study examined in that proceeding (Exhs. DPU-17; DPU-18; DPU-107). The average composite accrual rate is 5.12 percent, which Boston Gas acknowledges is one of the

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52 This adjustment includes a reduction of $11,311 in depreciation expense associated with the Waltham VNG station which the Company excluded from rate base (Exh. BGC-39, at 37).

53 As noted in Section II.A.1.c, above, Boston Gas withdrew its proposed telemetering addition to rate base, thus obviating the need to reflect the associated depreciation expense.

highest in the United States (Tr. 2, at 57). Among the plant components is the Company's LNG facility at Commercial Point, which has an estimated retirement date of 2000 and a depreciation accrual rate of 10.33 percent (Exh. AG-55, at III-2-3, Schedule of Indicated Remaining Life Accrual Rates at 2).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that the useful life of Boston Gas's Commercial Point facilities should be extended by an additional ten years beyond 2000 (Attorney General Brief at 72). In support of his proposal, the Attorney General argues that the president of Boston Gas testified that the Company's downstream assets, including Commercial Point, would have a useful life beyond 2000 (id. at 73, citing Tr. 1, at 120). Additionally, the Attorney General notes that the Company has proposed to implement its balancing service and its allocation of local production and storage costs during the term of the proposed PBR and multi-year unbundling plan and will continue at least through 2007 and beyond (Attorney General Reply Brief at 37, citing Exh. BGC-85).

The Attorney General contends that the Company's balancing proposal presumes the continued availability of Commercial Point beyond its anticipated retirement date (id. at 36-37, citing Exh. BGC-75, at 23-27). Additionally, he maintains that because Commercial Point plays a critical role in maintaining system integrity during weather changes and cold snaps, the facility will continue to be integral to the Company's distribution system into the foreseeable future (id., citing Exh. BGC-85).

Therefore, the Attorney General proposes that the Department direct the Company to rerun its 1993 depreciation study to account for the extended useful life of Commercial Point

(Attorney General Brief at 73; Attorney General Reply Brief at 37). In the alternative, the Attorney General suggests that the Department reduce the proposed depreciation expense by $2.3 million, based on his estimate of the extended useful life (Attorney General Reply Brief at 37, citing Exh. AG-55, Schedule of Indicated Remaining Life Accrual Rates at 2).[54]

b. The Company

Boston Gas contests the Attorney General's proposal, arguing that the Attorney General has provided no expert testimony or engineering judgment in this case to support his proposed revision (Company Brief at 117; Company Reply Brief at 41). The Company maintains that the testimony of Mr. Messer relied upon by the Attorney General fails to demonstrate that Commercial Point will have another ten years of life beyond the year 2001 (Company Brief at 117, citing Tr. 1, at 120). Furthermore, Boston Gas contends that the future ratemaking treatment of its downstream assets, including Commercial Point, will be the subject of Phase II proceedings, and therefore not necessary to address in this phase (id.). The Company also observes that the Attorney General's proposed adjustment is approximately $500,000 greater than the total test year depreciation expense associated with Commercial Point (Company Reply Brief at 41, citing Exh. AG-55, Schedule of Indicated Remaining Life Accrual Rates at 2).

3. Analysis and Findings

Depreciation expense allows a company to recover its capital investment in a timely and equitable fashion over the service lives of the investment. Milford Water Company, D.P.U. 84-135, at 23 (1985); Boston Edison Company, D.P.U. 1350, at 97 (1983). The

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54 The Department is unclear how the Attorney General derived his proposed adjustment; the total test year depreciation on Commercial Point was $1,802,944 (Exh. DPU-18).

selection of the appropriate accrual rate is largely determined by the useful life of the property. If the depreciation accrual rate is too low, depreciable plant would be removed from service before the capital investment in the plant is fully recovered. This would result in future ratepayers subsidizing present ratepayers, since future ratepayers would be charged with the expenses resulting from the earlier-than-anticipated retirement of plant, and consequent deficiencies in the depreciation reserve, that benefitted previous ratepayers. See Boston Gas Company, D.P.U. 19470, at 47-48 (1978). Conversely, if a depreciation accrual rate is set too high, capital costs will be recovered prior to the retirement of the plant. This would result in current ratepayers subsidizing future ratepayers, in that current and past ratepayers would have incurred all the costs associated with the plant, while future ratepayers would receive the benefit of the plant without responsibility for the cost of that plant. See D.P.U. 19470, at 51.

Although the Attorney General recommends a ten-year extension to the useful life of Commercial Point, he provided neither expert testimony nor engineering judgment in support of that position. In advancing his argument, the Attorney General relies primarily on the testimony of Mr. Messer, who did not testify as an engineering expert or as a depreciation expert. The record demonstrates that Mr. Messer's response concerned the anticipation that downstream assets would remain useful after the Company's proposed exit from the merchant function. While it is possible that plant facilities sited at Commercial Point will continue to play some role in the Company's operations after 2000, the evidence does not support a finding that the currently existing plant assets will fulfill that role. Moreover, if the physical plant at Commercial Point eventually is used as part of the Company's anticipated third-party balancing service, the Department's policy on nonutility allocations would apply.

D.P.U. 90-121, at 20-70; New England Telephone and Telegraph Company, D.P.U. 86-33-G at 113-201 (1989); Essex County Gas Company, D.P.U. 87-59, at 10 (1987). Accordingly, the Department declines to adopt the Attorney General's proposal, and finds that Boston Gas may continue to use its current depreciation accrual rate of 10.33 percent for Commercial Point.

Consistent with the Department's findings on the Company's proposed post-test year rate base additions, the Department shall exclude from cost of service $1,341,077 associated with the depreciation on 1996 system replacement investments. As noted in Section II.A.1.c, above, the Company has withdrawn its telemetering proposal and thus the $25,486 in proposed depreciation expense on this equipment. Accordingly, the Department shall exclude a total of $1,366,563 from Boston Gas's proposed depreciation expense. Consistent with our disposition of the proposed performance measurement systems, the Department shall exclude $560,000 in amortization expense from cost of service. Accordingly, the Department shall reduce the Company's proposed cost of service by a combined total of $1,926,563.

Q. Property Tax Expense

1. Introduction

During the test year, the Company booked $13,837,570 in property tax expense (Exhs. BGC-39, at 42; AG-51). Of this amount, the Company incurred $333,333 as an additional payment to the City of Boston as part of a settlement of property tax billings reached in 1993 ("Tax Settlement") (id.; Tr. 8, at 118-119). Under the terms of the Tax Settlement, Boston Gas will make the final tax payment by November 1, 1996 (Tr. 8,

at 119). Boston Gas stated that it has been engaging in discussions with the City of Boston regarding another possible settlement of property taxes starting in fiscal year 1998 (id.).

The Company eliminated the Tax Settlement payment from its test year cost of service, thus reporting a non-Tax Settlement property tax expense of $13,504,237 (Exhs. BGC-38, at 68; AG-51; RR-AG-59, at 42). Boston Gas then proposed an increase of $1,387,589 to its non-Tax Settlement property taxes to reflect: (1) an increase of $583,248 to reflect its annualized property taxes of $14,087,485; (2) a decrease of $63,018 to remove property taxes associated with nonutility plant and plant held for future use; and (3) an increase of $867,359 for additional property taxes attributed to its year-end plant investment for which property taxes have not yet been billed (Exh. BGC-39, at 42; RR-AG-59, at 42; Tr. 2, at 44-45).

With respect to this final adjustment, the Company stated that the cities and towns within its service area consistently assess the Company's property at 100 percent of net book value, which Boston Gas provides to the communities pursuant to G.L. c. 59, § 29 (Exhs. BGC-38, at 67; BGC-62). Application of fiscal year 1996 tax rates to the Company's December 31, 1995, net book values by community resulted in an increase of $867,359 (Exh. BGC-38, at 67).

By letter dated November 8, 1996, Boston Gas stated that its most recent property tax bills totalled $14,164,370 (Exh. DPU-21 Supp.). Of the 79 cities and towns in which the Company has personal property, ten communities have incorporated the December 31, 1995, plant investment balances in their assessment valuations (Exhs. BGC-62; DPU-21 (Supp.)). One community, the Town of Sudbury, has assessed the Company's property at a lower

value than either its fiscal year 1996 assessment or Boston Gas's December 31, 1995, net book value (Exhs. DPU-21 Supp.; BGC-62).[55]

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company's test year cost of service includes $333,000 in property taxes paid to the City of Boston as a result of the Tax Settlement (Attorney General Brief at 74, citing Exh. AG-51). The Attorney General contends that the final payment under the Tax Settlement will be made in October of 1996 (id. at 74, citing Tr. 8, at 119). The Attorney General argues that because the expense would be fully amortized by the date of this Order and hence nonrecurring, the Company's cost of service should be reduced by $333,000 (id.).

Again, the Attorney General assails the Company's proposal to recover expired and expiring amortizations as defying logic (Attorney General Reply Brief at 33). The Attorney General contends that the ratemaking principle of "ebb and flow" was not designed to cover "fictitious circumstances" or to serve as a guise for future test year ratemaking (id. at 33-34).

b. The Company

The Company maintains that, just as is the case with the ebb and flow of customer additions, there is an ebb and flow present in extraordinary expenses which are being amortized (Company Brief at 118). Boston Gas points to its preliminary discussions with the City of Boston regarding property taxes, which it claims may result in a future settlement similar to the Tax Settlement (id. at 118-119, citing Tr. 8, at 119). Boston Gas contends that

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55 Boston Gas claimed that the Town of Sudbury valued the Company's personal property at net book value (Exh. BGC-62).

there inevitably will be a new set of circumstances requiring amortization during the term of the PBR, which should be reflected in cost of service (id. at 119; Company Reply Brief at 40).

3. Analysis and Findings

The Department's general policy is to base property tax expense on the latest property tax bills a utility receives from the cities and towns. D.P.U. 93-60, at 220; D.P.U. 88-67, Phase I at 165-166; D.P.U. 84-94, at 19. Although the Company contends that it is currently in discussions with the City of Boston on a revised property tax settlement, the record clearly demonstrates that no agreement has been reached to date on future property tax billings. In essence, Boston Gas is proposing that rates be designed to recover unanticipated, unquantifiable costs based on some probability of future events. Because the Department does not permit a company to accumulate funds in advance through rates for future expenses, the Department rejects the Company's proposal to maintain a reserve for future amortizations. D.P.U. 95-118, at 122; D.P.U. 18268, at 8. The Department finds that by excluding the $333,333 Settlement payment from its test year cost of service, Boston Gas has overstated the required adjustment by a corresponding amount. Accordingly, the Company's reported test year cost of service shall be increased by $333,333, to reflect the actual test year expense of $13,857,570.

With respect to the Company's proposal to use its December 31, 1995, plant balances by community as a proxy for assessed valuation, the Department is unpersuaded that municipalities will necessarily base their valuations on net book value. While many communities in the Company's service area appear to base assessment valuations on net book values, this is by no means a universal practice. Moreover, even if a community used net

book value as a measurement of assessed valuation, it does not necessarily follow that net book values would continue to be relied upon for this purpose in the future. Therefore, the Department rejects Boston Gas's proposed method as speculative.

Based on the most recent property tax billings received by the Company, the Department finds that Boston Gas's property tax expense on utility plant is $14,164,370. This results in a revised adjustment of $306,800 over actual test year levels. Accordingly, the Company's proposed cost of service shall be reduced by $1,080,789.

R. Penalties

1. Introduction

During the test year, Boston Gas booked $12,853 in fines and penalties, mostly related to parking violations by Company vehicles responding to emergency service calls (Exh. DPU-46; Tr. 4, at 70, 73). The Company recorded this expense to Account 930 (Miscellaneous General Expenses), which is above-the-line for ratemaking purposes (Tr. 4, at 73). Boston Gas stated that these penalties represent a cost of doing business in an urban environment, as is found in the City of Boston (id. at 73-74). None of the parties addressed this issue on brief.

2. Analysis and Findings

The Department has found previously that fines and penalties paid by utility companies should be excluded from cost of service as a matter of public policy. D.P.U. 88-67, Phase I at 143 (1988); Kings Grant Water Company, D.P.U. 87-228, at 18-19 (1988); Nantucket Electric Company, D.P.U. 1530, at 26 (1983). Accordingly, the Company's proposed cost of service shall be reduced by $12,853.

S. Gain on Sale of Land

1. Introduction

During the test year, the Company sold a parcel of land in Gloucester with a book value of $2,206 to an unrelated party for $5,000 (Exh. DPU-69; Tr. 8, at 145). The Company did not propose to reflect the resulting gain of $2,794 in cost of service.

2. Analysis and Findings

The Department's long-standing policy with respect to gains on the sale of utility property has been to require the return to ratepayers of the entire gain associated with the sale, if those assets were recorded above-the-line and supported by ratepayers. D.P.U. 95-118, at 142; Barnstable Water Company, D.P.U. 93-223-B at 12 (1994). Therefore, if such property is sold by the utility, it is necessary to include an adjustment which reflects the appreciation on assets that ratepayers have supported in rates as reflected by a return on investment. Assabet Water Company, D.P.U. 95-92, at 29 (1996); D.P.U. 88-135/151, at 91.

The Department finds that a five-year amortization of the gain is appropriate. D.P.U. 95-118, at 144. Accordingly, the Company's proposed cost of service shall be reduced by $559.

T. Inflation Allowance

1. Proposal of the Company

The Company proposed initially an inflation adjustment of $1,176,952 (Exh. BGC-38, at 63). Boston Gas used the Gross Domestic Product chain weighted Price Index ("GDP-PI") in determining the inflation allowance of 2.96 percent for the period from the midpoint of 1995 through the end of 1996 (id. at 62). According to the Company, it

calculated the inflation adjustment by applying the projected GDP-PI to residual O&M expenses (Exh. BGC-39, at 35). Boston Gas submitted a revised schedule in which it proposed an adjustment of $1,237,268 to reflect its most recent inflation forecast of 3.07 percent and revised residual O&M expenses (RR-AG-59; Tr. 21, at 88-89).

Based on Boston Gas's stated objective that the inflation allowance be consistent with its PBR proposal, the Company proposed two modifications to the Department's standard method for calculating the inflation allowance. Specifically, Boston Gas proposed to: (1) use the GDP-PI instead of the Gross Domestic Product Implicit Price Deflator ("GDPIPD"); and (2) apply the inflation factor, from the midpoint of 1995 through the end of 1996, versus the midpoint of 1997. Boston Gas proposed the use of a shorter time frame because it considered that any inflation experienced after the date of the Order in this case would be recovered through the inflation component of its PBR (Exh. BGC-38, at 62). Likewise, Boston Gas explained that the Company selected the GDP-PI over the GDPIPD because the GDP-PI appeared to be the index of choice of other utilities that have proposed PBR mechanisms that include an inflation component (Tr. 3, at 168). In addition, Boston Gas indicated that the federal government has identified weaknesses in the GDPIPD, and therefore discourages the use of this index to measure inflation on a year-to-year basis (id.).

2. Analysis and Findings

The inflation allowance recognizes the fact that known inflationary pressures tend to affect a company's expenses in a manner that can be measured reasonably. D.P.U. 95-40, at 64; D.P.U. 93-60, at 192. The adjustment reflects the likely cost of providing the same level of service in the future as was provided in the test year. The Department permits utilities to increase their test year residual O&M by the projected GDPIPD for the period

from the midpoint of the test year to the midpoint of the rate year. D.P.U. 95-40, at 64; D.P.U. 92-250, at 97; D.P.U. 92-78, at 60. In order for the Department to grant a utility an inflation adjustment, the Department has required utilities to demonstrate all cost containment measures that they have implemented. D.P.U. 92-210, at 78.

With respect to the Company's selection of an inflation index, the Department finds that Boston Gas failed to provide any compelling argument to demonstrate that the GDP-PI is more reliable than the GDPIPD. The Company appears to be concerned that the GDPIPD may not be a reliable indicator of inflation over the anticipated PBR term. However, the inflation allowance is intended to address inflation over a shorter time period of, at the most, approximately two years. Accordingly, the Company shall use the GDPIPD to determine the Company's inflation allowance. Regarding the appropriate time frame to use in calculating the inflation allowance, the Department is rejecting the Company's proposal to implement the first increase under its price cap plan on the date of this Order. <u>See</u> Section XIII.C.2, below. Therefore, the Department shall base the inflation allowance on the period from the midpoint of the test year to the midpoint of the rate year. D.P.U. 95-40, at 64; D.P.U. 93-60, at 192. Based on the record, the inflation factor from the midpoint of the test year to the midpoint of the rate year is 3.93 percent (RR-DPU-79).

Accordingly, as outlined in Table 1, applying the updated inflation factor of 3.93 percent to the residual O&M expense determined in this Order by the Department results in an inflation allowance of $1,523,313.

Table 1

	Amount (000)
TEST YEAR O&M EXPENSE	$532,374,291
LESS: TEST YEAR ADJUSTMENT	
Gas Costs	$374,903,868
Wage and Salary Expense	$75,318,198
Health Care Expense	$6,783,489
Dental Expense	$737,348
Long Term Disability Expense	$21,350
Group Life Insurance Expense	$163,834
Bad Debt Expense	$13,960,000
AGA Dues Expense	$330,102
Public Relations Expense	$41,405
Public Liability Expense	$915,000
Quest Program Costs	$6,639,865
Charitable Contributions	$358,617
Customer Communication Expense	$311,521
Personal Computer Lease Expense	$380,051
Waltham Lease Expense	$99,679
Restructuring, Unbundling & PBR Proceeding Costs	$243,557
Lobbying Related Expense	$104,320
ECS Expense	$946,191
Executive Incentive Compensation	$353,099
Postage Expense	$1,929,106
Fixed Leases and Amortizations	$7,531,801
Subtotal	$492,072,401
O&M Expenses Subject to Inflation per Company	$40,301,890
LESS: DPU Adjustments	
Advertising Expense	$1,540,745
DPU Sub-total	$1,540,745
Residual O&M Expense	$38,761,145
Increase to be applied to the Company's Residual O&M Expense	3.93%
INFLATION ALLOWANCE	$1,523,313

V. CAPITAL STRUCTURE AND RATE OF RETURN

A. Capital Structure

At the end of its test year, Boston Gas's capital structure consisted of 46.24 percent long-term debt, 6.60 percent preferred stock, and 47.16 percent common equity (Exh. BGC-56, Sch. 11). Accordingly, this capital structure shall be used to determine the company's revenue requirement.

B. Cost of Long-Term Debt and Preferred Stock

In its initial filing, Boston Gas proposed an 8.12 percent cost rate for long-term debt, and a rate of 6.62 percent for preferred stock (id.). In determining its proposed cost rate of long-term debt and preferred stock, the Company reported that it generally used the method prescribed by the Department in D.P.U. 90-121 (Exhs. DPU-74; BGC-164). In that case, the Department prescribed that issuance costs shall be amortized over the life of the security issue which produced those costs without a return on the unamortized portion of the issuance costs. D.P.U. 90-121, at 159-161.

The Department finds that the Company has calculated its cost of long-term debt and preferred stock consistent with precedent. Accordingly, the Department finds that the effective cost of long-term debt is 8.12 percent, and that the effective cost of preferred stock is 6.62 percent.

C. Rate of Return on Equity

1. Introduction

Boston Gas proposed a 12.50 rate of return on common equity (Exh. BGC-56, at 1). In determining its proposed cost of equity, the Company relied on a discounted cash flow ("DCF") analysis, a risk premium analysis, a capital asset pricing model ("CAPM"), and a

comparable earnings approach. The spread of equity calculations ranged between 11.44 percent using a DCF model and 14.05 percent using a comparable earnings approach, with the average of all four approaches being 12.55 percent (id. at 7). Based on these results and its evaluation of the Company's relative risk to those of the barometer group as explained below, Boston Gas proposed a 12.50 percent return on common equity (id.).

Because Boston Gas is a wholly-owned subsidiary of Eastern, there are no market data for the Company's common stock, and consequently no means to assess directly investors's expectations of the Company's required return. Thus, the Company provided an analysis of seven companies ("barometer group") considered to be of generally comparable risk to Boston Gas[56] (id., Sch. 2, at 2). The resulting barometer group includes Bay State Gas Company, Connecticut Energy Corporation, Connecticut Natural Gas Corporation, Indiana Equity, Inc., Laclede Gas Company, New Jersey Resource Corporation, and Washington Gas Light Company (id.).

In addition to the use of a barometer group, the Company provided an analysis of the fundamental risk of Boston Gas in comparison to the barometer group and in comparison to Standard and Poor's ("S&P") Utility Index (id.). Boston Gas maintained that its investment risk was generally comparable to that of the barometer group, but that the Company also

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56 The selection criteria included: (1) companies listed in the S&P Utility Compustat II; (2) identification as gas distribution utilities with the Standard Industrial Classification Code 4924; (3) common stock traded on the New York Stock Exchange; (4) operations in the Northeast, Great Lakes, or North Central regions; (5) rated bonds; (6) no reduction or elimination of dividends; (7) permanent capital less than \$1.2 billion; (8) total revenues of at least \$100 million, but not more than \$1.2 billion; (9) more than 90 percent of 1994 revenues from gas sales (Exh. BCG-56, Sch. 2, at 2).

experienced higher risk traits, including: (1) weaker bond ratings; (2) higher debt leverage; and (3) lower creditor protection (id. at 2).

The four alternative methods used by the Company to measure its requested return on equity are addressed individually.

2. DCF Analysis

a. Introduction

A DCF postulates that the value of an asset is equal to the present value of future expected cash flow discounted at the appropriate risk-adjusted rate of return (id. at 3). In its simplest form, the DCF theory considers two components: (1) the anticipated cash dividend yield; and (2) the future growth appreciation of the investment (id.). The Company used the following equation to model its DCF analysis:

Expected Return on Common Equity	K= (D1/Po) + g

where K is the investor's required cost of capital, D1 is the anticipated dividend, Po is the stock price, and g is the expected growth rate (id.).

As a basis for determining the dividend yield component of the DCF model, Boston Gas calculated a median dividend yield for the barometer group of 5.75 percent for the twelve, six, and three months average for the period ending March 1996, based on the then-current stock prices (id. at 3, Sch. 5). For the purpose of its DCF analysis, the Company then adjusted the dividend yield to take into consideration the expectation by investors that dividends would increase over the coming period (id. at 3). This adjustment resulted in a 5.94 percent adjusted dividend yield component for the barometer group (id.).

To derive the growth rate for its comparison group, the Company analyzed four indicators for the barometer group: (1) the five-year and ten-year historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share; (2) the historic internal growth rates for each Company for the years 1991 through 1995; (3) the analysts's five-year projected growth rates in earnings per share, dividends per share, book value per share, and cash flow per share; and (4) the analysts's five-year projected short-run earnings growth rates (RR-DPU-31). Based on these Company-specific historical and prospective growth rates and a market-wide factor of 0.5 percent, the Company maintained that a 5.50 percent prospective growth rate is a reasonable expectation for the barometer group (Exh. BGC-56, at 3-4). Boston Gas then added the dividend yield and dividend growth rate estimates, producing an 11.44 percent rate of return on equity for the barometer group of companies (id. at 3).

b. Positions of the Parties

i. Attorney General

The Attorney General criticizes Boston Gas's selected dividend yield and growth rate (Attorney General Brief at 51-52). First, the Attorney General argues that by dividing the indicated dividend by the current market price, the resulting dividend yield is highly susceptible to the impact of "one day" events that may affect the market (id. at 52). To adjust for any abnormalities resulting from the use of such spot prices, the Attorney General advocates the use of the average of the months of high and low stock prices (id., citing RR-AG-45). Based on the most recent average twelve and six month high-low dividend yields of 5.7 and 5.66 percent, and a 3.58 percent dividend growth, the Attorney General proposes the use of a dividend yield rate of 5.78 (id. at 55).

Second, the Attorney General asserts that there is no factual basis for the Company's proposed growth rate (id. at 53). The Attorney General points out that Boston Gas's selected growth rate estimate of 5.50 percent is 279 basis points above the historical dividend growth rate and 307 basis points above any projected dividend growth rate of the comparison group (id. at 53-54, citing RR-DPU-31). The Attorney General asserts that the Department previously has found that the appropriate growth rate to employ in a DCF analysis is the retained earnings growth rate, which he contends strikes an appropriate balance between the earnings per share growth rate and dividends per share growth rate (id. at 54, citing D.P.U. 84-25, at 163; D.P.U. 1720, at 102. The Attorney General contends that the five-year historical average from retained earnings for the barometer group was 1.50 percent, and the forecasted growth from retained earnings is 4.49 percent (id., citing RR-DPU-31). The Attorney General proposes the average of these two numbers as the growth rate, or 3.00 percent (id.). However, according to the Attorney General, the Department also gives weight to investment analysts's consensus forecasts of earnings per share (id., citing D.P.U. 86-33-G at 356. The Attorney General proposes to use the average of the Company's updated schedules of the five-year projected growth rates of the S&P earnings per share of 4.29 and the IBES Mean of 4.03 to arrive at an average for the barometer group of 4.16 percent (id., citing RR-DPU-31, Sch. 7, at 1). Combining the average of 3.00 percent for retained earnings growth with the average of 4.16 percent for the projected growth rates, the Attorney General arrives at a growth rate of 3.58 percent (id. at 55).

Based on his proposed dividend yield rate of 5.78 percent and a growth rate of 3.58 percent, the Attorney General asserts that 9.36 percent is a reasonable estimate of the cost of equity for the Company using a DCF analysis (id.). The Attorney General contends that this

rate represents a reasonable risk spread from the recent 6.62 percent cost of preferred stock, which he claims is a conservatively high estimate of the Company's cost of debt (Attorney General Reply Brief at 32)

ii. The Company

The Company argues that the Attorney General has arbitrarily attempted to average two overlapping high-low yield periods (Company Brief at 133). According to the Company, this results in double-counting the dividend yield for the past six months (id.). Boston Gas argues that the only valid yield component developed on this record is a combination of the twelve-month, six-month, and three month averages, which is 5.75 percent, adjusted to reflect the prospective nature of dividends payments of 5.94 percent (id. at 132-133). The Company disputes the Attorney General's claims that the dividend yield is based on a "spot price" (id. at 132). According to the Company, Mr. Moul calculated the dividend yields based on month-end prices, adjusted to remove the pro rata accumulation of the quarterly dividend amount since the last ex-dividend date, and established a price which will reflect the true yield on a stock over time (id.). In addition, the Company criticizes what it considers to be the Attorney General's selectivity in his proposed ROE.

c. Analysis and Findings

In the past, the Department has addressed the DCF analysis as a basis for determining an appropriate rate of return on equity. See D.P.U. 95-40, at 96-97; D.P.U. 93-60, at 250-251. As indicated above, the Company-proposed DCF model postulates that the value of an asset is equal to the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. Because the dividend yield and growth rate components of this risk-adjusted rate of return are variables that reflect investors's

expectations of future performance of stock investment, there always will be potential problems and limitations in estimating the appropriate values of these two variables.

Regarding the growth component of the DCF, the Department previously has rejected those adjustments that tend to overstate the dividend yield or the growth component and, consequently, the DCF-based cost of equity. More specifically, the Department has rejected financing and market adjustments and those adjustments which could double-count the effect of the growth rate factor. D.P.U. 95-40, at 97; D.P.U. 93-60, at 250; D.P.U. 90-121, at 178-180. In addition, the Department has rejected the inclusion of financing and market adjustments because investors incorporate a premium into their expected return to reflect market risks and financing costs. D.P.U. 95-40, at 97; D.P.U. 90-121, at 178-180. In this case, Boston Gas added a .50 percent adjustment to the growth rate of 5.00 percent to account for market-wide factors. Therefore, the Department finds that the Company's DCF analysis overstates the required return on common equity for Boston Gas.

The Department does not concur with the Attorney General's emphasis on the retained earnings growth method as a means to estimate investor-expected growth. The retained earnings growth rate does not necessarily capture the full growth potential of a company. D.P.U. 93-60, at 251. A variety of quantitative factors, including growth in earnings per share and dividends per share, should be taken into consideration as well. D.P.U. 93-60, at 251; D.P.U. 92-250, at 147; D.P.U. 88-135/151, at 125. The Attorney General's growth estimate overemphasizes the role of retained earnings in deriving the growth rate.

Based on the above considerations, the Department finds that the Company's DCF analysis overstates the required return on common equity for Boston Gas. Therefore, the Department shall place limited weight on the Company's DCF analysis.

3. CAPM Analysis

a. Introduction

Boston Gas noted that the CAPM, unlike the risk premium approach which considers industry and company-specific factors, reflects only the systematic risk as measured by a stock's beta (Exh. BGC-56, at 6). The CAPM postulates that the cost of equity for a particular stock is equal to the rate of return of a risk-free investment plus a risk premium which recognizes the riskiness of the stock relative to the overall riskiness of the market (id.). To compute the cost of equity using the CAPM, three components are necessary: (1) the risk-free rate of return; (2) the beta, which measures the risk that cannot be eliminated from a portfolio of assets through diversification, also known as systematic risk; and (3) the market risk premium (id. at 6, Sch. 10).

The Company used the following equation to model its CAPM analysis:

Expected Return on
Common Equity $K = Rf + b\ (Rm-Rf)$

where K is the investor's required return, Rf is the return on risk-free investments, b is the beta for the security being analyzed, and Rm is the return in the market (id.). The Company used two models of the CAPM analysis -- the traditional Sharpe-Lintner model and a zero-beta model (id.).

For the Sharpe-Lintner model, Boston Gas used the yield on 30-year Treasury bonds for the twelve months ending in March 1996, as well as forecasted data, to measure the risk-free rate of return (id., Sch. 10, at 4-5). The Company stated that, based on historical

and forecasted data, the most representative risk-free rate for use in the CAPM was 6.50 percent (id. at 6) To derive the beta for the barometer group, the Company relied on data from Value Line Investment Survey and the Merrill Lynch Security Price Index and determined that the median beta for the barometer group was 0.55 (id.). In determining the market risk premium, the Company used two sets of data: (1) the Value Line forecast of capital appreciation and dividend yield on 1,700 stocks; and (2) the total returns from common stocks and long-term government bonds published by Ibbotson Associates in Stocks, Bonds, Bills and Inflation--1996 Yearbook ("SBBI") (id., Sch. 10, at 5-6). The Company used the average of these two market risk premiums, or 7.24 percent, as its proposed market risk premium for its CAPM analysis (id. at 6). Using the risk-free rate of 6.50 percent, a beta of 0.55, and a market risk premium of 7.24 percent, Boston Gas concluded that the appropriate return on equity using the Sharpe-Linther model is 10.48 percent (id.).

For the zero-beta model, the Company used the intermediate term Treasury note yield of 6.25 percent as the risk-free rate (id.). The market premium of 7.42 percent was calculated in a manner similar to the traditional CAPM model (id.). Then, one half of this market premium, or 3.71 percent, was added to the risk-free rate of return yielding a 9.96 percent risk-free rate (id.). The remaining market premium of 3.71 percent was adjusted to account for the systematic risk of the barometer group (id.). Thus, using the risk-free rate of 9.96 percent, a beta of .55, and one half of the adjusted market risk premium of 3.71 percent, Boston Gas concluded that the appropriate return on equity using the zero-beta model is 12 percent (id.).

The Company used the average of the two CAPM models or 11.24 percent as the lower range of the CAPM method. According to Mr. Moul, the upper range of 13.19

percent includes an additional 1.95 percent upward adjustment to compensate for the discrepancy that exists between the actual returns of the smaller size companies included in the barometer group and their expected higher returns based on CAPM results (id. at 6-7). In support of his small capitalization adjustment for the barometer group, Mr. Moul provided copies of an article by Eugene F. Fama and Kenneth R. Frech, The Cross Section of Expected Stock Returns (Journal of Finance, June 1992, at 427-465) (RR-DPU-28).

b. Positions of the Parties

i. Attorney General

The Attorney General contends that the Department should reject the CAPM analysis because of the Company's reliance on unrealistic assumptions and its poor application in the instant case (Attorney General Brief at 57-58). The Attorney General observes that the Department has noted deficiencies in the following underlying assumptions in CAPM analyses: (1) investors can borrow and lend an unlimited amount of funds at risk-free rates; (2) alternative equity/securities portfolios can be mathematically evaluated; (3) there are no income taxes; and (4) a 100 percent liquidating dividend is paid at the end of the investment period (id. at 58). The Attorney General argues that while investors might find certain of these assumptions highly desirable, none holds true in the real world, and the theoretical construct of the CAPM theory fails to explain the many different analysis techniques and investment strategies used by investors (id.).

Further, the Attorney General argues that the Company's application of CAPM in this case is fundamentally flawed (id. at 59). First, the Attorney General argues that the Department has never found that Boston Gas's reliance on the Ibbotson Study reflects current investor expectations (id. at 59-60).

The Attorney General also criticizes the Company's selection of betas (id at 60-61). The Attorney General argues that the betas selected by Boston Gas are not the only ones available to investors (id. at 60). He contends that the range of betas available for a single company is diverse, and that differing betas produce differing results (id.). More important, according to the Attorney General, Boston Gas's beta is fundamentally flawed because statistically it explains only three percent of the variation in stock prices (id.). The Attorney General argues that because the beta selected by the Company fails to explain 97 percent of the variation in stock price, the beta is rendered useless for evaluating a utility's return on equity (id., citing D.P.U. 92-250, at 158; D.P.U. 84-94, at 63-64; Berkshire Gas Company, D.P.U. 1490, at 74-75 (1983)).

In addition, the Attorney General claims that Mr. Moul inflated his CAPM results by performing a so-called zero-beta analysis (id.). According to the Attorney General, Mr. Moul's zero-beta analysis is so subjective in the development of the zero-beta risk free rate and market premiums that the results are meaningless (id. at 61). Further, the Attorney General asserts that Mr. Moul could have found returns anywhere from 10.33 percent to 13.67 percent by applying different weighting to the market premium assigned to the zero-beta portfolio or the market adjusted systematic risk of the barometer group (id.).

ii. The Company

The Company acknowledges that the Department has expressed skepticism in the past concerning the validity of the CAPM model as an indicator of the cost of common equity (Company Brief at 136). Boston Gas concedes that, although the Company included the zero-beta form of the CAPM, no useful purpose can be realized in trying to persuade the Department that the method is more useful than the Department had felt it to be in the past

(id.). However, the Company notes that three economists have been awarded Nobel prizes based on their work on CAPM, and that investors and analysts consistently use this model (id.). Boston Gas maintains that the 12.21 percent return on common equity derived by the CAPM analysis is consistent with the results of the other methods employed by Mr. Moul (id. at 137).

c. Analysis and Findings

The Department in the past has rejected the use of the CAPM as a basis for determining a utility's cost of equity. D.P.U. 92-78, at 113; D.P.U. 88-67, Phase I at 184; D.P.U. 84-94, at 63-64. The Department has noted a number of limitations in the application of CAPM, including the definition and data used to estimate the risk-free rate, and the coefficient of determination of beta. D.P.U. 93-60, at 257.

Based on the record presented in this case, the Department finds that the same deficiencies in CAPM identified in prior cases remain present here. Moreover, we are unpersuaded that the Company's zero-beta analysis produces a reliable estimate of the required cost of equity. Accordingly, the Department gives no weight to the Company's CAPM analysis in this case.

4. Risk Premium Analysis

a. Introduction

The risk premium analysis postulates that the cost of equity capital is equal to the interest on long-term corporate debt, defined herein as the interest rate on A-rated public utility bonds, plus an equity risk premium (Exh. BGC-56, at 4). Boston Gas stated that the risk premium approach recognizes the required compensation for the more risky common equity over the less risky and more secure investment in debt (id.).

The Company used the following equation to model its risk premium analysis:

Expected Return on Common Equity	K = i + RP

where K is the investor's required return, i is the prospective return for long-term public utility debt, and RP is the equity risk premium (id. at 5).

Boston Gas relied on A-rated public utility bond yields as its starting point in its risk premium analysis (id. at 4). As the interest component of its risk premium approach, the Company proposed a 7.50 percent yield based on Moody's Investors Services, Inc. ("Moody's) 12-months ending March 1996, historical rates and Blue Chip Financial Forecasts ("Blue Chip") yields on A-rated public utility long-term debt as of April 1, 1996 (id. at 5).

To determine the appropriate equity risk premium, the Company used a 1928-1995 data series and assumed four alternative holding periods.[57] Based on this information, the Company determined that a risk premium of 5.00 percent represents a reasonable reflection of the relative riskiness of Boston Gas and the barometer group compared with the S&P Public Utilities (id. at 5). Accordingly, the Company's risk premium analysis results in a cost of equity of 12.50 percent, which is the sum of the 5.00 percent risk premium plus the 7.50 percent rate which is based on historical and prospective long-term debt rates (id.)

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57 This series and the holding periods are based on Ibbotson & Associates, Lehman Brothers Bond Index, and the Federal Reserve Statistical Releases (Exh. BGC-56, Sch. 9; Tr. 11, at 68-69).

b. Positions of the Parties

i. Attorney General

The Attorney General contends that Boston Gas's risk premium analysis is virtually identical to the Company's CAPM analysis, including its reliance on the use of beta and the Ibbotson Report (Attorney General Brief at 64). The Attorney General contends that Boston Gas relied solely on beta to quantify the difference in risks that exists in the larger universe of equities (Attorney General Reply Brief at 30). In addition, the Attorney General maintains that Mr. Moul did not incorporate into his risk premium analysis the eight different measures of risk mentioned in his testimony (id.). The Attorney General maintains that, based on its criticism of the Company's CAPM analysis and for all of the reasons mentioned above, the Department should reject Boston Gas's risk premium analysis (Attorney General Brief at 64).

ii. The Company

Boston Gas disputes the Attorney General's contention that the risk premium and CAPM analyses are essentially the same, and claims that different inputs are required for each approach (Company Brief at 137). The Company contends that, unlike the CAPM, the risk premium model does not require the use of a risk-free rate or a beta, but is rooted in the intuitively sound assumption that investors require a higher return on equity than on debt (id.).

The Company maintains that the Department has expressly sanctioned the use of long-term utility bonds as the debt instrument in a risk premium analysis (id., citing D.P.U. 88-135/151, at 124. Regarding its use of the Ibbotson Report, Boston Gas argues that Mr. Moul relied heavily on risk premiums based on shorter periods, and claims that the

relatively consistent results demonstrate that the resulting risk premium fairly represents the additional risk shareholders assume in deciding to purchase utility stock (id. at 138). Finally, Boston Gas maintains that its risk premium analysis relies on eight measures of risk, and not solely on beta, to derive its equity risk premium (id.).

c. Analysis and Findings

The Company's risk premium analysis, which defines the cost of equity capital to be equal to the interest on long-term corporate debt, defined by the Company as the interest rate on A-rated public utility bonds, has been presented to the Department in previous rate cases and rejected. The Department has found that the risk premium approach overstates the amount of company-specific risk and, therefore, overstates the cost of equity. D.P.U. 93-60, at 261; D.P.U. 90-121, at 171; D.P.U. 88-67, Phase I at 182-184.

In addition, the Department has rejected specific aspects of the risk premium analysis, including the use of the average of more than 60 years of annual data that showed a large statistical variance making the result of the analysis of little practical value. D.P.U. 95-40, at 97; D.P.U. 93-60, at 262; D.P.U. 92-111, at 265-266. While the Company did use shorter time periods in its analysis, the Department still places little weight on those risk premiums developed from data covering what we find to be unreasonably long periods. Because the Company's risk premium analysis presented in this case suffers from the same limitations previously noted by the Department, we give limited weight to this approach as a basis for determining the Company's cost of equity in this case.

5. Comparable Earnings

a. Introduction

The Company presented the comparable earnings approach as an additional method to supplement its DCF and risk premium analyses, noting that this approach has been used extensively in rate of return analysis for over a half century. The comparable earnings approach uses a set of parameters which identifies similar risk characteristics of a utility and a group of companies with comparable risk that are not public utilities (Exh. BGC-56, at 2).

To implement the comparable earnings approach, the Company used both historical realized returns and forecasted returns for non-utility companies taken from the Value Screen Data Base, published by Value Line, as a measure of a fair rate of return on common equity (id.). In order to establish the comparability of the non-regulated companies with Boston Gas, the Company used six criteria covered in the Value Screen Data Base: (1) timeliness rank of 3 and 4 (from a high of 1 to a low of 5); (2) safety ranks of 1 and 2 (from a high of 1 to a low of 5); (3) financial strength ratings of B+, B++, and A (from a high of A++ to a low of C); (4) price stability 50 and higher (based upon a high of 100 to a low of 5); (5) a range of Value Line betas between .45 to 0.70 (above 1.0 there is more risk involved); and (6) technical rank of 2, 3 and 4 (based upon a high of 1 to a low of 5) (id., Sch. 4, at 1; RR-DPU-29). By applying these selection criteria, the Company identified a group of eleven companies to be used in the comparable earnings approach (Exh. BGC-56, Sch. 4, at 1).

Boston Gas stated that the results of this approach indicate that the historical return on book common equity was 12.4 percent for the five years ending 1994, and that the forecast rate of return on book common equity is 15.7 percent (id. at 2). The Company stated that the average of the historical and forecast rates of return on common equity is 14.05 percent,

which represents the comparable earnings result in this case (id.). The Company stated that the comparable earnings approach is consistent with the Company's proposal to move from cost of service regulation to incentive based regulation. According to the Company, Boston Gas's risk will increase in the future and, as a result, the ratesetting process should emulate the returns achieved by non-regulated firms operating in a competitive market (id.).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the Department repeatedly has found the comparable earnings analysis unreliable, and urges the Department to reject Boston Gas's comparable earnings approach (Attorney General Brief at 64, citing D.P.U. 93-60, at 265-266 (1993); D.P.U. 92-250, at 160-161; D.P.U. 92-111, at 280-281; D.P.U. 905, at 48-49. The Attorney General asserts that because the Company has provided no reasons for the Department to deviate from its precedent, the Company's proposed comparable earnings approach should be rejected (id. at 65).

The Attorney General claims that while the Company included three indicators of investment risk in its analysis,[58] Boston Gas ignored two other important indicators: (1) price growth performance; and (2) earnings predictability (id.). The Attorney General argues that stock price and earnings stability are important risk indicators that a stock investor would consider. By failing to incorporate these additional indicators, Boston Gas's comparable earnings analysis of the non-regulated companies is questionable at best (id. at 64).

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[58] In his reply brief, the Attorney General indicated that Mr. Moul based his comparable earnings analysis on six indicators and not three as the Attorney General noted in his initial brief (Attorney General Reply Brief at 30).

ii. The Company

The Company contends that the Attorney General's criticism of Boston Gas's comparable earnings approach contains three factual errors (Company Brief at 139). First, Boston Gas argues that, contrary to the Attorney General's assertion that only three indicators were used, the Company used all six indicators from Value Line's Value Screen Data Base to conduct its comparable earnings analysis (id.). Second, Boston Gas disputes the Attorney General's argument that the Company has not provided any reason in this case for the Department to change its well-founded precedent regarding the validity of the comparable earnings analysis (id.). As argued by the Company, the comparable earnings approach is more relevant to a measurement of the Company's cost of equity as the Company proposes to move from cost of service regulation to performance-based regulation. According to the Company, this regulatory change will entail more risk for the Company and, as such, the ratesetting process should emulate the returns achieved in a competitive environment (id.). Third, Boston Gas disputes the Attorney General's argument that price growth performance and earnings predictability were not part of Mr. Moul's analysis. The Company asserts that Mr. Moul used all the measures contained in the Value Screen Data Base (id. at 140).

c. Analysis and Findings

While the comparison group of companies used in the comparable earnings approach consists of non-regulated firms, the Company has not demonstrated that the eleven companies included in the comparison group have risk comparable to that of Boston Gas. In order to meet the comparability criteria enunciated by the Supreme Court in Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679

(1923) ("Bluefield") and Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1942) ("Hope"), other investment risk criteria, including the nature of the business, must be evaluated carefully as bases for selecting an appropriate comparable group of companies. The Department notes that the companies used in the comparable earnings analysis include representatives of such industries as financial services, machine products, petroleum, food processing, and diversified companies (Exh. BGC-56, Sch. 4, at 1). While these companies may fall within the six investment risk criteria used in the analysis, the Attorney General has correctly indicated that the Company did not consider other relevant investment risk indicators. Furthermore, the Department notes that the investment risk criteria selected by Boston Gas may not represent the most valid criteria. For example, we note that the use of beta as a criterion in selecting the comparable group of companies is not a reliable investment risk indicator given its statistical measurement limitations previously noted. Accordingly, the Department rejects the Company's comparable earnings approach as a basis for determining the Company's cost of equity in this case.

6. Conclusion

The standard for determining the allowed return on equity is set forth in Bluefield and Hope. The allowed return on common equity should preserve the Company's financial integrity, allow it to attract capital on reasonable terms, and be comparable to earnings on investments of comparable risk. Bluefield and Hope. The Department has considered various factors in setting an appropriate return on equity, including the historical and projected growth rates, the Company's most recent long-term bond offering rates, the growth rates on a number of economic indicators, and the range of returns on equity granted in recent Department rate cases.

Based on a review of the evidence presented in this case, the arguments of the parties and the considerations set forth above, the Department finds that an allowed rate of return on common equity of 11 percent is within a reasonable range of rates that satisfies the standards set forth by the Court in Bluefield and Hope, and is appropriate in this case.

VI. COST ALLOCATION AND RATE DESIGN

A. Introduction

Rate structure is the level and pattern of prices that various classes of customers are charged for use of a particular utility service. A class's rate structure is determined by the cost of serving that rate class and by the structure of charges designed to collect that cost. The Department's goals for utility rate structure are efficiency, simplicity, continuity, fairness, and earnings stability. D.P.U. 93-60, at 331-332 (1993); D.P.U. 92-78, at 116; D.P.U. 1720, at 112-120.

There are two steps in developing rate structure: cost allocation and rate design. Cost allocation entails assignment of a portion of a utility company's total costs to each rate class. Rate design entails determining a set of prices for each class that will produce revenues equal to the costs allocated to that class. D.P.U. 93-60, at 331-332; D.P.U. 92-78, at 116; D.P.U. 1720, at 112-120.

In order to permit the development of a rate structure that meets the Department's objectives, the allocation process should determine an overall revenue requirement for each class that reflects the costs a company incurs to serve that class. Cost allocation comprises five tasks. The first task is to functionalize costs. In this step, costs are defined as being associated with the production, storage, or transmission and distribution function of providing service. The second task is to classify expenses in each functional category according to the

factors underlying their causation. Thus, the expenses are classified as demand-, energy-, or customer-related. The third task is to identify an allocator that is most appropriate for costs in each classification within each function. D.P.U. 93-60, at 331-332; D.P.U. 92-78, at 116; D.P.U. 1720, at 112-120.

The fourth task is to allocate all of a company's costs to each rate class based upon the cost groupings and allocators chosen, and to sum these allocations in order to determine the total cost of serving each rate class. The fifth and final task is to compare the cost of serving each rate class to the revenues produced by that rate class using the rate design in effect during the test year. If the difference between these amounts is small, the total revenue increase or decrease may be allocated among all rate classes to equalize rates of return and to ensure that each class pays for the costs it imposes. If any differences between the allocated costs and test year revenues are significant, the revenue increase or decrease may, for reasons of continuity, be allocated to reduce differences in rates of return without equalizing them in a single step. D.P.U. 93-60, at 331-332; D.P.U. 92-78, at 116; D.P.U. 1720, at 112-120.

B. Cost Allocation

The Company filed two allocated cost of service studies. The first study allocates Company-wide costs and expenses and the second study allocates the costs of local production and storage facilities. In addition, the Company filed a study to determine the appropriate percentage split of the costs of local production and storage facilities between base rates and the CGAC. These three studies are addressed below.

1. Allocated Cost of Service Study for Company-Wide Costs

a. The Company's Proposal

The Company filed an allocated cost of service study ("COSS") that allocates Company-wide costs and revenues to various rate classes based on cost responsibility (Exh. BGC-108, at 3). The COSS identified the cost of serving each rate class, determined the revenue requirements by season for each rate class, and identified whether cross-subsidies exist (id.). Since the Company's loads, costs and revenues vary substantially between the summer and winter months, the COSS allocated those costs and revenues based on each rate class's utilization of the Company's services during different time periods (id.).

The Company stated that its COSS promotes two goals: fairness and efficiency (id.). The Company noted that based on the results of the COSS, it is possible to determine during each time period whether each rate class is paying its fair share of the costs it is imposing on the system (id. at 3-4). The Company added that the COSS promotes efficiency because the Company uses it as the basis for a marginal cost study and for rate design to ensure that customers in each rate class not only are charged the total costs of serving them but also are charged the correct marginal costs of serving them at each point in time (id. at 4).

The Company's allocation procedure involves several steps. First, the Company functionalized costs into groups of physical functions, whether in the production of gas, the transmission and distribution ("T&D") of gas, or other general purposes (id. at 5). Second, the Company classified costs into three causal components which reflect the reasons the Company has incurred each of the functionalized costs (id. at 5-6). Third, the Company developed allocators for costs within each function (id. at 6). Fourth, the Company applied the allocators to assign the various Company costs to rate classes, time periods, and causal

components (id. at 6). In this step, all the costs assigned to each rate class by time period are summed to yield the allocated costs of serving the class during the summer and winter periods (id. at 6). Finally, the Company compared the cost of serving each class to the revenues generated by that class and the overall Company revenue requirement to determine whether the class is paying the costs of serving it during each time period (id. at 7). The Company uses this comparison to determine any cross-subsidization that may exist among rate classes (id. at 7).

The Company stated that its proposed COSS incorporated three changes in response to Department directives in D.P.U. 93-60. First, demonstration and selling expenses (Account 912) were allocated on a direct assignment of expenses to the class sectors for which the expenses are targeted (id. at 2). Second, customer account supervision (Account 901), customer records and collection (Account 903), and miscellaneous customer accounting expenses (Account 905) were allocated based on employee time spent on serving each specific rate class (id. at 2-3). Finally, administrative and general expenses (Accounts 920, 921, 922, 923, 925, 928, 930, and 931) were allocated based on the Company's distribution service revenue requirement (id. at 3; Exh. BGC-110). No party commented on the Company's proposed COSS.

b. Analysis and Findings

The Department finds the Company's proposed COSS to be consistent with Department precedent and its directives in D.P.U. 93-60. Accordingly, the Department approves the Company's proposed COSS. The Department directs the Company in its compliance filing to re-run its COSS to allocate costs and expenses consistent with this Order.

2. Allocated Cost of Service Study for Local Production and Storage Facilities

a. The Company's Proposal

The Company performed an allocated cost of service study in order to determine the appropriate allocation among rate classes of the costs of local production and storage facilities ("P&S COSS") (Exh. BGC-113). Based on the results of the P&S COSS, the Company applied the percentage split, described in Section VI.B.3 below, on each class revenue requirement attributable to local production and storage facilities to determine the appropriate portion of costs recoverable through the base rates and the costs recoverable through the CGAC (id., Sch. 29).[59]

The structure of the P&S COSS is similar to the main COSS (RR-DPU-5). The Company indicated that while the main COSS covers the three functional areas of production and storage, T&D, and administrative and general expenses, the P&S COSS covers only production and storage, with the associated administrative and general expenses, and excludes expenses related to the T&D function (id. at 1).

During the proceeding, the Company stated that a further review of its initially-filed P&S COSS indicated an error in calculating the appropriate percentage allocation of customer accounting and administrative and general expenses (id. at 2-3). The Company filed a revision of the relevant schedules in the initially-filed P&S COSS to correct this error

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59 The net revenue requirement attributable to local production and storage facilities is $15,935,000 which the Company allocated among rate classes based on the results of the P&S COSS (Exh. BGC-113, Sch. 29-1, ln. 26). The Company applied the proposed 21.5/78.5 percent split on each class's revenue requirement attributable to local production and storage facilities to determine the portions recoverable through base rates and through the CGAC (id.). In the Company's revised P&S COSS, the net revenue requirement attributable to local production and storage facilities is $18,062,000 (RR-DPU-78, Sch. 29-1, ln. 26).

(RR-DPU-78). The Company indicated that the revised calculations would be consistent with the P&S COSS approved by the Department in D.P.U. 93-60 (Tr. 20, at 148). No party commented on the Company's proposed P&S COSS.

b. Analysis and Findings

The Department finds that the Company's revised P&S COSS is consistent with the method approved by the Department in D.P.U. 93-60. See D.P.U. 93-60, at 335, 430. Accordingly, the Department approves Boston Gas's P&S COSS. The Department directs the Company in its compliance filing to re-run its P&S COSS using the revenue requirement consistent with this Order.

3. Allocation of Local Production and Storage Costs

a. The Company's Proposal

In the Company's last rate case, the Department directed the Company to develop an analytical method that would separately identify the cost components associated with local production and storage costs attributable to the purposes of meeting demand and deliverability needs. D.P.U. 93-60, at 432. Pursuant to that directive, the Company proposed to recover 21.5 percent of the costs of local production and storage facilities (LNG and propane) through the base rates and to recover the remaining 78.5 percent through the CGAC (Exh. BGC-75, at 12). The proposed 21.5/78.5 percentage split is based on a study filed in compliance with the Department's directive in D.P.U. 93-60 (id.).

In determining this proposed percentage split, the Company postulated that the maximum probable hourly load increase, due to a rapid decrease in temperature, could "quantify the amount of the Boston Gas peak-shaving supplemental facilities (LNG and propane) that may be required to maintain distribution integrity during hour-to-hour changes

in demand" (Exh. BGC-85, at 1). The Company determined this maximum probable hourly load increase in four steps.

First, using hourly data for the period December 1, 1995, through February 15, 1996, the Company estimated 24 simple linear regression equations, corresponding to each hour of the day, to estimate the change in load per unit change in temperature ("load-to-temperature coefficient") (id. at 1-2; Exhs. DPU-26; DPU-27). Second, the Company estimated the difference between the average hourly temperature change and the maximum negative temperature change for that hour based on hourly temperature data from December 1, 1995, through February 15, 1996 (Exh. BGC-85, at 1-2). The Company assumed that this difference represents the maximum temperature change which would result in the "greatest unanticipated increase" in load (id. at 2). Third, the Company determined the swing volume for a given hour by multiplying the estimated load-to-temperature coefficient for that hour by the difference between the average hourly temperature change and the maximum negative temperature change for that hour (id. at 3). Finally, the Company selected the largest value among the estimated 24 hourly swing volumes, giving a maximum value of 3,233 MMBtu (id.).

The proposed 21.5 percent allocation in base rates of the costs of LNG and propane facilities is the ratio of 3,233 MMBtu and 15,058 MMBtu (id.). The denominator of this ratio represents the combined equivalent hourly firm (excluding standby) production capacity of LNG (291,400 MMBtu) and propane (70,000 MMBtu), assuming a constant hourly rate of production over a given day (id.).[60]

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60 The Company initially indicated "[n]one of the propane plants have what is referred to as 'stand-by'" (RR-DPU-20). Subsequently, however, the Company indicated that, (continued...)

The Company stated that it is premature at this time to determine the long-term resources required to accommodate load swings because a different mix of resources might be required to provide such services as the Company accommodates more third party nominations (Exh. BGC-75, at 13).[61] The Company added that as it moves toward 100 percent transportation, it may revise its proposed 21.5/78.5 percentage split because a better method of determining and dealing with the hourly load variations could be developed (Exh. DPU-32). The Company stated that it would seek Department approval if a change is necessary in the appropriate percentage split (id.).

During the proceeding, the Company indicated that, in meeting demand both under expected design and normal weather conditions, the Company would consider its total LNG and propane capacity, including standby capacity (Tr. 20, at 110-111). If the existing total LNG and propane deliverability of 476,200 MMBtu were used in the calculations, the equivalent even hourly production rate would be 19,842 MMBtu and the resulting percentage split would be 16.29/83.71 percent (RR-DPU-75). The Company, however, indicated that

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[60](...continued)
like the case of its LNG plants, the Company "selects certain vaporizers to provide standby capability in the event of a malfunction of the other LPA Vaporization equipment" (RR-DPU-74; Tr. 20, 78-79).

[61] Based on the Company's growth forecasts as of July 1996, and assuming that the Distrigas contract will be renewed and that suppliers will deliver their normal daily contract quantities, the Company estimated that, based on design year peak day calculations, there would be excess firm LNG capacity that would be available for leasing up to year 1999 (54,068 MMBtu in 1997, 26,637 MMBtu in 1998, and 9,343 MMBtu in 1999) and propane up to year 2000 (70,000 MMBtu from 1996 through 1999 and 56,672 MMBtu in 2000) (DPU-RR-22). For example, over the period December 1, 1995, through February 15, 1996, no propane was dispatched (Exh. DPU-26). In the case of LNG, the average hourly throughput over the same period ranged from 552 to 1,145 MMBtu and the hourly average LNG throughput, as percentage of hourly average system throughput, ranged from 3.5 to 5.3 percent (id., Att. 2).

total deliverability of 476,200 MMBtu is not achievable if all units are operating simultaneously, and that the standby capacity ensures that the total firm deliverability of 361,400 MMBtu is made available (id.).

In the absence of normal hourly degree day data, as the basis for hourly load swing calculations, the Company compared the maximum daily load swings based on actual temperature data, with the corresponding maximum daily load swings based on normal effective degree day ("EDD") and on Typical Meteorological Year ("TMY") EDD data (RR-DPU-24).[62] The Company computed the maximum daily load swings for these three sets of degree day data using the regression coefficients of its dispatch model (estimated based on May 1995, through April 1996, actual EDD data) (id.). The computed maximum daily load swings based on the normal EDD, the TMY EDD, and the actual EDD are 158,718, 169,960, 167,568 MMBtu, respectively (id., Att. 1, at 4).

In addition, the Company calculated three sets of hourly swing volumes using three sets of estimated hourly temperature data, applying the same method shown in Exhibit BGC-85.[63] The maximum hourly swing volumes for these three sets of calculations were

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62 The TMY EDD is constructed month-by-month choosing actual months from the Company's historical EDD data set such that the total monthly EDD approximates the total mean values based on TMY (RR-DPU-24). The Company notes, for example, that the TMY months of November, January, and March are the same historical months used by the Company in its normal EDD data set (id.).

63 The first set of hourly temperature data was developed based on a linear interpolation of the hour-to-hour temperature differences of the 3-hour-interval Logan temperature data for the period November through April using the TMY EDDs; the second set is based on the same TMY EDDs but assuming that the value of the three-hour temperature change occurs in the hour of observation; the third set is the hourly actual temperature data for the period December 1, 1995, through February 15, 1996, but using linear interpolations for the intervening hours assuming that there are only three-hour intervals of temperature data available (DPU-RR-25).

2,198, 6,814, and 2,417 MMBtu, respectively (RR-DPU-25, at 2). The Company reasoned that given the assumptions used in estimating and interpolating the three sets of temperature data, the 3,233 MMBtu, proposed to represent the maximum hourly load swing, is a reasonable figure that falls within the range of the above-stated estimates of maximum hourly load swings (Tr. 20, at 105-106).

b. Positions of the Parties

i. Distrigas

Distrigas opposes Boston Gas's proposal to include in base rates and charge both sales and transportation customers 21.5 percent of the costs of local production and storage facilities (Distrigas Brief at 10-11).[64] Distrigas claims that in D.P.U. 93-60, the Department recognized the lack of support for Boston Gas's proposal but allowed Boston Gas to charge a portion (25 percent) of such costs to transportation customers provided Boston Gas subsequently filed appropriate justification (id. at 11, citing Tr. 5, at 228-229). Distrigas states that the Department also rejected the study filed by Boston Gas in 1994 (id., citing Tr. 5, at 228).

Distrigas contends that the study filed by the Company in this case is flawed (id. at 11). Distrigas claims that Boston Gas's study looks only at the relationship between temperature and demand but "does not establish any relationship between the change in

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64 Only Distrigas commented on the Company's proposal in this case. In D.P.U. 93-60, DOER and TEC opposed the Company's proposal to recover a portion of local production and storage costs through base rates. D.P.U. 93-60, at 414-421. The Attorney General, in that case, suggested that the Department require the Company to file a study based on its post-FERC Order 636 experience with transportation services. Id. at 413-414.

temperature and the change in demand" (id. at 12).[65] Distrigas adds that although Boston Gas may experience rapid drops in temperature, there is no evidence that such temperature changes are unanticipated because Boston Gas receives daily weather forecasts (in three-hour intervals) with more updates when forecasts change by more than two degree days (id.).

Distrigas claims that there is no evidence that a large one-hour drop in temperature results in a corresponding rapid increase in demand (id.). Distrigas notes, for example, that the actual hour on January 3, 1996, which saw the largest temperature drop of eight degrees, corresponded to an actual reduction of 1,400 MMBtu in sendout for that hour, and not an increase of 3,233 MMBtu as the study predicted (id. at 13). Distrigas also notes that although the winter hours of 1995-96 had high temperature variability, the Company used little or no LNG to respond to the temperature changes (id. at 13).

Distrigas claims that there is no evidence to show that the Boston Gas's local production facilities are actually used to cope with hourly load increases (id.). Distrigas asserts that local production facilities are not required to manage hourly load variations, unless the pipeline and underground storage contracts are being fully utilized (id. at 14, citing Tr. 20, at 107). Distrigas, however, adds that during those time periods when pipeline and underground storage contracts are being fully utilized, the Company is simply using its local production facilities as a source of supplemental supply to cope with the high loads, whether or not there is any hourly load variability (id. at 14). Distrigas asserts that the

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65 Distrigas questions the logic of the Company's position. More specifically, Distrigas notes that, although Boston Gas acknowledges that its study does not examine the relationship between change in temperature and change in demand, the Company also asserts that its study "provides a sound method by which to specify the impact of a temperature change and the resulting system balancing requirements" (Distrigas Reply Brief at 4, citing Company Brief at 148).

associated costs of local production and storage facilities should, therefore, only be allocated to the Company's sales services (id. at 14).[66]

Distrigas also claims that the Company has considerable flexibility in its pipeline and underground storage capacity to cope with hourly load swings during most days of the year (id. at 13-14). This flexibility includes the use of no-notice service, the ability to change nominations during the day on as little as one-hour notice, and the ability to take deliveries at greater than 1/24 of the daily quantity (id.). Distrigas concludes that since Boston Gas is unable to justify, for the second time, why transportation customers should pay for the cost of local production and storage costs, the Department should reject the Company's proposal at this time (Distrigas Brief at 14; Distrigas Reply Brief at 4-5).

ii. The Company

The Company states that in D.P.U. 93-60 the Department found that the Company's local production and storage costs are properly allocable between base rates and the CGAC (Company Brief at 146). The Company asserts that Distrigas's position in this case is contrary to this previous Department finding (id.).

The Company claims that its study does not necessarily examine or explain the relationship between the change in temperature and change in demand (id. at 147). Instead, the study determined a statistical relationship between sendout and temperature (or what the Company referred to as "heating increment") that would predict hourly swing volumes which in turn provide a basis for understanding system balancing requirements (id.). The Company

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66 Distrigas claims that Boston Gas admits that the portion of the local production facilities at issue performs a dual function, that of a pure gas supply source and as a tool for managing hourly load variations (Distrigas Brief at 14 n.8, citing Tr. 5, at 228). Distrigas argues that this would imply that at best only a portion of the 21.5 percent of local production costs could be put in base rates (id.).

notes that although changes in load are at times smaller than predicted, there are also times when changes in loads are greater than predicted thereby necessitating the development of a formula that would capture average expected results (id.).

The Company admits that it is unlikely to be left fully unaware of impending temperature changes (id. at 148). Boston Gas, however, asserts that weather is not a fully predictable phenomenon and that the best known forecast cannot reliably predict the hour-to-hour temperature changes (id.). The Company argues that in specifying an unexpected temperature change, as the factor to be multiplied by a heating increment, the Company recognizes unpredictability in loads and that it "has facilities to handle such occurrences" (id.). The Company concludes that Distrigas's proposal not to allocate any costs of LNG and propane facilities in transportation rates would leave sales customers uncompensated for the use of those assets by transportation customers (id.).

c. Analysis and Findings

In D.P.U. 93-60, the Department rejected the Company's proposal to recover the class's allocated costs of local production facilities through the base rates of the G-44 and G-54 rate classes and recover the costs of storage facilities through the CGAC. D.P.U. 93-60, at 430.[67] In that Order, the Department noted that, although no precedent exists for the recovery of local production and storage plants in transportation rates, the

[67] In D.P.U. 93-60, the Department approved transportation rates that would be available to both sales and transportation customers for the G-44 and G-54 rate classes. In that Order, the Department noted that the amount of local production plant was approximately equal to the amount of the associated storage facilities. The Company's proposal in that case, to allocate the costs of local production through base rates and the costs of the associated storage facilities through the CGAC, was, therefore, approximately equivalent to a 50/50 percentage split. D.P.U. 93-60, at 429-430.

Department found "that it is appropriate for transportation customers to pay additional and commensurate level of costs for ... transportation service." Id. at 428, 430-431. The Department, in the absence of a study that precisely identified the appropriate cost allocation, directed the Company to recover 75 percent of the test year costs associated with both local production and storage facilities through the CGAC and to recover the remaining 25 percent of those costs through the base rates. Id. at 430.

The Department, however, noted that local production and storage facilities are primarily used to meet sales customers's demand, and emphasized the need to develop transportation rates that reflect the true cost of transportation service in the Company's system. Id. at 430-31. Accordingly, the Department directed the Company to perform an allocation study that would identify the cost components of production and storage related facilities that appropriately are recoverable in base rates and through the CGAC and to "present the results of this study to the Department within one year from the date of this Order ...." Id. at 432.

In Boston Gas Company, D.P.U. 93-60-G (1994), the Department rejected the Company's allocation study filed in response to the above-stated directive. D.P.U. 93-60-G at 3. The Department noted that the compliance study filed therein did not provide adequate documentation to explain the method and assumptions used. Id. In addition, the Department noted that the study failed to identify the cost components of production and storage related facilities that appropriately are recoverable in base rates and through the CGAC. Id.

In the instant case, the Department notes that the Company's study did not directly identify the cost components of production and storage related facilities that are appropriately recoverable in base rates and through the CGAC. The Company's study, however, applied

an indirect or proxy approach by determining the maximum hourly load swing that could occur and using this level of hourly load swing to apportion the costs of local production and storage facilities that would be recoverable in base rates and the CGAC.

Based on the record in this case, the Department notes a number of concerns about the Company's proposed proxy approach. This approach assumes that an estimated maximum hourly load increase could represent the portion of capacity of the Company's supplemental facilities (LNG and propane) that would be required to maintain distribution integrity during hour-to-hour changes in demand. In turn, it is assumed that this capacity level could be used also to apportion the costs of supplemental facilities between base rates and the CGAC.

The reasonableness of the above-described assumptions and the acceptability of the estimated maximum hourly load increase appear questionable when evaluated on the basis of the record in this case. First, although the Company provided alternative estimates using normal degree day data consistent with Department ratemaking practices, the record indicates that the estimated 3,233 MMBtu was based on the assumption that such estimate would represent the "greatest unanticipated increase" in load. The Company, however, acknowledges on brief that "it is unlikely to be caught fully unaware of impending temperature changes." Given this qualification, the record is not clear whether the Company's initial assumption, that the difference between the average hourly temperature change and the maximum negative temperature change for that hour, representing the maximum temperature change which would result in the "greatest unanticipated increase" in load, would still hold. If in fact the Company may not be caught fully unaware of impending temperature changes, then it also may not be caught fully unaware of the

corresponding load changes, given the Company's estimates of "heating increments" as a basis for forecasting load. Accordingly, the estimated 3,233 MMBtu may no longer represent the "greatest unanticipated increase" in load.

Second, the record indicates that the Company's existing pipeline and storage contracts provide significant sources of flexibilities that allow the Company to make hourly changes in nominations. The Company does not appear to have adequately considered this flexibility in its analysis. Third, although the record indicates that the Company considers and uses all of its supplemental facilities in planning for and meeting the load requirements for both normal and design weather conditions, the Company used only firm capacity, instead of total capacity including standby, as the basis for its calculations. If, for example, the Company used its total capacity in its calculations, the resulting percentage split would be different. Fourth, the record indicates that the Company has excess LNG and propane capacity which it plans to lease. Therefore, by using the existing supplemental capacity, as the basis for allocating costs between base rates and the CGAC, such allocation may not be reflective of the true cost of transportation service in the Company's system.

As the Company correctly noted during the proceeding, it would be difficult to determine the long-term resource mix that might be required to accommodate load swings as the Company accommodates more third party nominations. Accordingly, as the Company's service structure moves toward full transportation, any percentage split based on test year and present information may have to be revisited from time to time.

For example, the Department notes that in a fully unbundled market, where the Company may have fully exited the merchant function, recovery of a portion of the costs of LNG and propane facilities through base rates may not be consistent with either the structure

of such an unbundled market or the price signals that would be generated in a competitive gas market. As the post-FERC Order 636,[68] 636-A,[69] and 636-B[70] ("Order 636")[71] environment evolves, the gas market could provide increasing levels and varieties of services and opportunities for matching supply and demand both at the LDCs's city-gate and at the customers's burner-tip. In turn, such services and opportunities could cover not only supply reliability but also gas deliverability. Consequently, the issue of recovering a portion of the costs of local production and storage facilities through base rates may no longer exist.

Accordingly, based on the record in this case and considering the ongoing transition and evolution of the gas industry toward greater competition, the Department finds that the Company's proposed 21.5/78.5 percentage split does not provide a reasonable allocation of the Company's costs of local production and storage facilities between base rates and the CGAC.

As a transition mechanism, however, and consistent with the Department's finding in D.P.U. 93-60 that "it is appropriate for transportation customers to pay additional and commensurate level of costs for ... transportation service," the Department shall continue to allow the recovery of a portion of the costs of local production and storage facilities through

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68 Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation and Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol, FERC Order No. 636, 57 Fed. Reg. 13,267 (April 16, 1992), III FERC Stats. and Regs. Preambles ¶ 30,939 (April 8, 1992).

69 57 Fed. Reg. 36,128 (August 12, 1992), III FERC Stats. and Regs. Preambles ¶ 30,950 (August 3, 1992).

70 57 Fed. Reg. 57,911 (December 8, 1992), 61 F.E.R.C. ¶ 61,272.

71 For an overview of the restructuring of the natural gas industry as a result of the implementation of FERC Order 636, see Order on Standard of Review and Confidentiality, D.P.U. 93-187/188/189/190, at 2-4 (1994).

the base rates. Accordingly, the Department, based on the record in this case and our reasoned judgment, directs the Company to recover 15 percent of the costs of local production and storage facilities through the base rates and the remaining 85 percent through the CGAC. The Department directs the Company in its compliance filing to design rates consistent with this Order.[72]

C. Marginal Cost Study

1. Description

The Company filed a marginal cost of service study ("MCS") that included analyses of the increased costs that the Company would incur if it expanded its services through the addition of customers, increased sales of gas, or the addition of capacity (Exh. BGC-108, at 30). According to Boston Gas, use of the MCS in setting rates enhances the efficient use of resources by sending the proper price signals to its customers (id. at 31). The MCS was prepared by Paul M. DeRosa using the same method as the one the Department approved in the Company's last rate case, D.P.U. 93-60 (id.). The Company prepared an unbundled (no gas costs included) MCS that included the calculation of marginal distribution capacity costs, and marginal customer costs (id.).

2. Marginal Distribution Capacity Costs

The Company used the prospective additions method approved in the Company's last rate case, D.P.U. 93-60, to calculate marginal distribution capacity costs (id. at 33). According to the Company, marginal distribution capacity costs consist of the long-run

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72 The 85/15 percent split between the CGAC and base rates approved in this case results in a $1,174,030 [(.215-.15) * (18,062,000)] reduction of the costs of local production and storage facilities to be recovered in base rates. See RR-DPU-78, Sch. 29-1, ln. 26. The final adjustment shall be based upon the Company's compliance allocated costs of service studies.

marginal cost of upgrading the existing T&D system and the cost of main extensions to that system (id.). For upgrading the existing T&D system the Company determined a cost of $77.23 per design day MMBtu by dividing the five-year engineering estimate of upgrades to existing facilities necessary for system capacity growth by the estimated additional load (Exh. BGC-114, Sch. 1, at 1).

The Company then calculated the cost of extensions to its T&D system. The Company derived this figure by multiplying the weighted cost per foot of mains over the last three years by the number of feet required for each additional design day MMBtu, reduced by the required customers's contributions, to arrive at a cost of $350.38 per design day MMBtu (id.). The Company determined the number of feet required for each additional design day MMBtu through a 15-year regression analysis (id., Sch. 1, at 4). The Company added the marginal cost of T&D system reinforcements and T&D system extensions to arrive at a total marginal distribution cost of $427.61 per design day MMBtu (id., Sch. 1, at 1). None of the parties commented on the Company's marginal distribution capacity costs.

The Department finds the Company calculated its proposed marginal distribution capacity costs consistent with the method approved in D.P.U. 93-60. Accordingly, the Department finds the Company's proposed marginal distribution capacity costs to be acceptable.

3. Marginal Customer Costs

The Company's marginal customer costs consist of (1) the cost of the line from the main to the customer's building (service line), and (2) metering costs (Exh. BGC-108, at 35). The Company calculated these two costs for each rate class. With respect to the cost of the service line, the Company subtracted, for each rate class, the required customer contribution

from the total cost of the service line, to determine the marginal service costs (id.). None of the interveners commented on the Company's marginal customer costs.

The Department finds the Company calculated its proposed marginal customer costs consistent with the method approved in D.P.U. 93-60. Accordingly, the Department finds the Company's proposed marginal customer costs to be acceptable.

D. Rate-by-Rate Analysis

The Company unbundled its rates in D.P.U. 93-60, which resulted in all gas costs being recovered in the Gas Adjustment Factor ("GAF"). According to the Company, unbundling its rates enabled the Company to be indifferent between transportation customers and firm sales customers from a revenue requirement basis (Exh. BGC-75, at 14). Except for two newly proposed rates, G-45 and G-55, which would be made available to firm-sales and transportation customers, the Company's proposed residential and C&I rates consist of a customer charge, a headblock energy charge, and a tailblock energy charge, for the peak and off-peak periods. The peak period proposed by the Company covers the season from November through April, and the off-peak period covers the season from May through October. The G-45 and G-55 rates consist of a customer charge, and a reservation charge for the peak and off-peak periods (Exh. BGC-94, at 14).

In designing its proposed rates, the Company did the following. First, the Company stated that it moved closer to cost-based customer charges to reduce intra-class subsidies and to promote fairness (Exh. BGC-75, at 10). Second, the Company stated that it set the peak tailblock rate approximately equal to the marginal non-gas costs to promote efficiency (Exh. BGC-75, at 11). Third, the Company stated that it set the headblock and tailblock rates at a level such that approximately 50 percent of customer bills would terminate in the

headblock and 50 percent in the tailblock (id. at 11). However, where feasible, the Company set a single volumetric charge to make the rates simpler for customers to understand and easier for the Company to administer (id.).

With respect to the C&I rates, the Company was concerned that some classes would receive high increases based on the results of the bill impacts (Tr. 6, at 95). Therefore, the Company proposed to spread the total increase to C&I classes across all C&I rates on an average basis (id.). Accordingly, the Company proposed to increase all C&I rate classes by 9.8 percent, which is the average increase for all C&I classes based on the Company's original filing (id.).

In designing rates, the Department's objective has been to base rates on marginal costs because this leads to an efficient allocation of resources. If the Department finds that marginal cost-based rates represent a change that violates the goal of rate continuity, then the rates must be adjusted in a way that does not violate this goal. D.P.U. 95-40, at 144-145; D.P.U. 93-60, at 367-368.

Based on a review of the annual bill impacts on customer classes, the Department finds that at equalized rates of return the Rates G-54 and G-17 customer classes would receive increases that violate the Department's rate continuity goal. Accordingly, as shown in Schedule 10, we direct the Company to shift $339,507 from rate class G-54 to the remaining C&I customers. We direct the Company to allocate this revenue shift on cost to serve each C&I class. In addition, as shown in Schedule 10, because of rate continuity concerns, we direct the Company to shift $29,500 from rate class G-17 to the other street lighting class, G-7.

A discussion of the Department's findings on the design of each of the Company's rates, and how that design reflects the Department's various rate design goals, is set forth below. The rate-by-rate analysis that follows evaluates the specific rates proposed by the Company and provides the Company with direction for setting its rates in the compliance filing. This direction includes the Department's findings as to the appropriate customer charges and tailblock rates.

1. Rate R-1 and Rate R-3: Residential Non-Heating and Heating

a. The Company's Proposal

Rate R-1 is available to all residential customers who do not have gas space heating equipment, while Rate R-3 is available to all residential customers who have gas space heating equipment. Both R-1 and R-3 require that a customer take service through one meter in a single building that contains no more than four dwelling units (Exh. BGC-94, at 1-3). The Company proposed to increase the monthly customer charge from $7.00 to $10.00 for Rate R-1, and from $8.50 to $15.00 for Rate R-3 (Exh. BGC-75, at 14-15).

The proposed R-1 energy charge during the peak season is $0.4866 per therm for the first 20 therms consumed and $0.1237 for each additional therm. The proposed R-1 energy charge during the off-peak season is $0.4866 per therm for the first 10 therms consumed and $0.1237 for each additional therm (Exh. BGC-83, at 1).

The proposed R-3 energy charge during the peak season is $0.3262 per therm for the first 150 therms consumed and $0.1932 for each additional therm. The proposed R-3 energy charge during the off-peak season is $0.3210 per therm for all therms consumed (id.). Also, to bring the peak and off-peak headblock charges closer together, the Company proposed to

shift $12 million from the off-peak period to the peak period where it is spread over larger peak period volumes (Exh. BGC-75, at 15; Tr. 6, at 98).

b. <u>Positions of the Parties</u>

i. <u>Intervenors</u>

With respect to rates R-1 and R-3, the Attorney General, DOER, NEEC, and MOC all state that the Company's proposed increases to the customer charges result in unreasonably high rate increases for low-use residential customers, and therefore, violate the Department's rate structure goals of fairness and continuity. Accordingly, the aforementioned parties argue that the Company's proposed customer charge increases should be moderated (Attorney General Brief at 83-85; DOER Brief at 46-47; DOER Reply Brief at 9-10; NEEC Brief at 4-5; MOC Brief at 26-28; MOC Reply Brief at 3-4).

ii. <u>The Company</u>

Boston Gas states that its proposed customer charges are based on an embedded cost study using Department-approved methods (Company Brief at 81). According to the Company, without customer charges set at the full embedded cost levels there are intra-class subsidies with low use customers being subsidized by high use customers, violating the Department's goal of fairness (Company Brief at 81). The Company states that its proposal follows the Department's continuity goal by gradually moving to "embedded cost pricing" of the customer charge over the course of its proposed PBR (Company Brief at 81). In conclusion, the Company maintains that its rate design proposal will increase efficiency in price signals and will encourage energy efficiency measures that have the greatest economic value, because its rate design proposal moves the Company's rate structure closer to its cost

structure (Company Brief at 83). Therefore, the Company maintains that the Department should approve its proposed customer charges.

c. Analysis and Findings

According to the Company's MCS, the total peak season marginal costs for Rates R-1 and R-3 are $0.1237 and $0.1932 per therm, respectively (Exh. BGC-114, Sch. 11, at 1). Based on a review of marginal costs and the seasonal and annual bill impacts on customers, the Department finds that an R-1 Rate designed with a $8.00 monthly customer charge for the peak and off-peak seasons and a $0.1237 tailblock rate for both the peak and off-peak seasons, satisfies continuity goals and produces bill impacts that are moderate and reasonable. Based on the R-3 marginal costs and seasonal and annual bill impacts, the Department finds that a $9.50 monthly customer charge for the peak and off-peak seasons and a $.1932 tailblock rate for both the peak and off-peak seasons, satisfy continuity goals and produces bill impacts that are moderate and reasonable. In addition, to prevent the off-peak commodity headblock charge from being priced significantly higher than the peak headblock charge the Company is directed to shift revenues so as to price both the peak and off-peak commodity charges at the same rate.

Therefore, the Department directs the Company to set the R-1 and R-3 charges as follows. For Rate R-1, the Department directs the Company to set the breakpoints between headblock and tailblock rates at 20 and 10 therms in the peak and off-peak seasons, respectively, and to set the seasonal headblock rates at the same charge for each season to collect the remaining class revenue responsibility as specified on Schedule 10. For Rate R-3, the Department directs the Company to set the breakpoints between headblock and tailblock rates at 150 and 30 therms in the peak and off-peak seasons, respectively, and to set the

seasonal headblock rates at the same charge for each season so as to collect the remaining class revenue responsibility as specified on Schedule 10.

2. Rate R-2 and Rate R-4: Residential Non-Heating and Heating Subsidized Rates

Subsidized rates are available to residential customers who are recipients of Fuel Assistance, Supplemental Security Income, Aid to Families with Dependent Children, General Relief, Refugee Resettlement, Food Stamps, Medicaid, or Veterans Benefits (Exh. BGC-94, at 2-4). Currently, customers on Rates R-2 and R-4 receive a 40 percent reduction from base rates R-1 and R-3, respectively (Exh. DPU-132).

To be consistent with the settlement agreement approved in Boston Gas Company, D.P.U. 90-17/18/55, at 3-4 (1990), and its last rate case, D.P.U. 93-60, at 383-385, the Company proposed to set the discount rate equal to the rate that would provide a total subsidy of $5 million (Exh. BGC-75, at 14). Based on the Company's calculations, the resulting discount rate would be 37 percent (Exh. DPU-132). For Rate R-2 the discount rate is applied to the customer and commodity charges of Rate R-1, and for Rate R-4 the discount rate is applied to the customer and commodity charges of Rate R-3. The Company proposed to allocate the low-income shortfall back to the other classes on a rate-base allocator (Exh. BGC-81).

On brief, the Company modified its proposal to maintain the low-income discount rate at its current level, which is 40 percent (Company Brief at 87). The Company states that the Low Income Intervenors support its modified proposal (id., citing Low-Income Intervenors Brief at 6-8). The Department finds maintaining the low-income discount rate at 40 percent is appropriate because it is consistent with the discount level approved in D.P.U. 93-60. No parties objected to this discount level. Accordingly, the Department directs the Company to

set the discount rate at 40 percent and to collect the low-income shortfall from the other classes using a rate base allocator.

3. Rate G-41: C&I Low Use, Low Load Factor

The G-41 rate is available to C&I customers whose maximum hourly meter capacity is between zero and 500 cubic feet per hour and whose metered use in the most recent peak period of November through April is greater than or equal to 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. BGC-94, at 5).

The Company proposed to increase the monthly customer charge from $20.00 to $25.00 (Exh. BGC-75, at 16). The Company proposed to eliminate the current headblock and tailblock features of Rate G-41 in favor of flat volumetric commodity charges for the peak and off-peak periods (id.). The proposed commodity charge during the peak season is $0.2924 per therm, and the proposed commodity charge during the off-peak season is $0.2371 per therm (Exh. BGC-94, at 5). Lastly, the Company proposed to move $75,000 from the off-peak to the peak period to enable it to better design flat volumetric rates (Exh. BGC-75, at 16). None of the intervenors commented on the Company's proposed design of Rate G-41.

Pursuant to the Company's MCS, the total peak season marginal cost for Rate G-41 is $0.2091 per therm (Exh. BGC-114, Sch. 11, at 1). Accordingly, based on a review of marginal costs and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $22.00 monthly customer charge and flat commodity rates for the peak and off-peak seasons, satisfies continuity goals and produces bill impacts that are moderate and reasonable. In addition, the Department finds that to price the peak

commodity charge at a higher rate than the off-peak commodity charge, the Company must shift $1.3 million in base revenues from the off-peak to the peak season.

Therefore, the Department directs the Company to set the Rate G-41 charges accordingly. The Department also directs the Company to collect in the commodity charge the remaining class revenue responsibility as specified on Schedule 10.

4. Rate G-42: C&I Medium Use, Low Load Factor

The G-42 rate is available to C&I customers whose maximum hourly meter capacity is between 501 and 1500 cubic feet per hour and whose metered use in the most recent peak period of November through April is greater than or equal to 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. BGC-94, at 6).

The Company proposed to increase the monthly customer charge from $35.00 to $45.00 (Exh. BGC-75, at 16). The Company proposed to eliminate the current headblock and tailblock features of Rate G-42 in favor of flat volumetric commodity charges for the peak and off-peak periods (id.). The proposed commodity charge during the peak season is $0.2605 per therm and during the off-peak season is $0.2229 per therm for all therms consumed. None of the intervenors commented on the Company's proposed design of Rate G-42.

According to the Company's MCS, the total peak season marginal cost for Rate G-42 is $0.2019 per therm (Exh. BGC-114, Sch. 7, at 1). Based on a review of marginal costs and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $38.50 monthly customer charge and flat commodity rates for the peak and off-peak seasons, satisfies continuity goals and produces bill impacts that are moderate and

reasonable. In addition, the Department finds that to price the peak commodity charge at a higher rate than the off-peak commodity charge the Company must shift $900,000 in base revenues from the off-peak to the peak season.

Therefore, the Department directs the Company to set the Rate G-42 charges accordingly. The Department also directs the Company to collect in the commodity charge the remaining class revenue responsibility as specified on Schedule 10.

5. Rate G-43: C&I High Use, Low Load Factor

The G-43 rate is available to C&I customers whose maximum hourly meter capacity is between 1,501 and 12,000 cubic feet per hour and whose metered use in the most recent peak period of November through April is greater than or equal to 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. BGC-94, at 7).

The Company proposed to increase the monthly customer charge from $100.00 to $125.00 (Exh. BGC-75, at 17). The proposed commodity charge during the peak season is $0.2105 per therm for all therms consumed (Exh. BGC-94, at 7). The proposed commodity charge during the off-peak season is $0.1818 per therm for all therms consumed (id.). None of the intervenors commented on the Company's proposed design of Rate G-43.

According to the Company's MCS, the total peak season marginal cost for Rate G-43 is $0.2053 per therm (Exh. BGC-114, Sch. 11, at 1). Based on a review of marginal costs and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $110.00 monthly customer charge and flat commodity rates for the peak and off-peak seasons, satisfies continuity goals and produces bill impacts that are moderate and reasonable. In addition, the Department finds to price the peak commodity charge at a

higher rate than the off-peak commodity charge the Company must shift $500,000 in base revenues from the off-peak to the peak season.

Therefore, the Department directs the Company to set the Rate G-43 charges accordingly. The Department also directs the Company to collect in the commodity charge the remaining class revenue responsibility as specified on Schedule 10.

6. Rate G-44 & Rate G-45: C&I Extra-High Use, Low Load Factor

a. The Company's Proposal

The G-44 rate is available to C&I customers whose maximum hourly meter capacity is greater than 12,000 cubic feet per hour and whose metered use in the most recent peak period of November through April is greater than or equal to 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. BGC-94, at 8). Currently, the G-44 class rate structure is based on a customer charge and an estimated maximum demand charge (Exh. BGC-75, at 17).

The Company proposed to return Rate G-44 to a volumetric billing basis, based on its assertion that customers find the current demand billing method confusing (id.; Tr. 6, at 100). In addition, the Company proposed to: (1) increase the monthly customer charge from $400.00 to $450.00 (Exh. BGC-83, at 1); (2) set the commodity charge for the peak season at $0.2010 per therm for all therms consumed; and (3) set the commodity charge for the off-peak season at $0.1622 per therm for all therms consumed (Exh. BGC-94, at 8).

The Company also proposed to create a new rate class, G-45 (Exh. BGC-75, at 19). According to the Company's proposal, customers who are currently served on Rate G-44 and whose annual usage is greater than 25,000 MCF would be served on Rate G-45 (id. at 19). The Company proposed to design Rate G-45 on a metered demand basis; that is, their

monthly billing determinant would be the highest daily usage in the billing month (id. at 19). Also, the Company proposed to install telemetry devices to record the daily demand for those G-45 customers who do not currently have them (id.).[73] The Company proposed to include the cost of these meters in the class revenue requirement (id.; BGC-110).

b. Positions of the Parties

i. DOER and NEEC

DOER and NEEC argue that the Company's proposed rates G-44 and G-45 have unacceptably large variations in their impact on customers and, therefore, violate the Department's continuity goal (DOER Brief at 90; NEEC Brief at 3-5). Accordingly, DOER and NECC state that the Department should reject the Company's proposal and, instead, should recombine Rates G-44 and G-45 under the current rate design, as shown in Record Request DPU-51 (DOER Brief at 90, NEEC Brief at 5-6).

ii. The Company

Based on the adverse bill impacts associated with the Company's proposed design of rates G-44 and G-45, the Company proposes to withdraw its initial proposal for these two rates (Company Brief at 87). Instead, the Company proposes a single G-44 Rate, designed according to the method currently in effect (id.). The Company states that its revised proposal eliminates the need to telemeter the proposed G-45 customers and, therefore, reduces its proposed ratebase by $358,452 (id.).[74]

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73 Telemetry devices are necessary to obtain daily usage information used for billing.

74 This is addressed in Section II.A.1.c of this Order.

c. Analysis and Findings

Based on a review of seasonal and annual bill impacts on customers, the Department agrees with DOER, NEEC and the Company that the Company's proposed design of rates G-44 and G-45 produces adverse bill impacts. Accordingly, the Department directs the Company to establish a single G-44 Rate, designed according to the method currently in effect for Rate G-44. This alternative is supported on brief by DOER, NEEC, and the Company.

Based on a review of the bill impacts on customers, as well as the marginal and embedded costs, the Department finds that a rate designed with a $450.00 monthly customer charge moves the customer charge closer to its underlying cost and satisfies the Department's continuity goal. Therefore, the Department directs the Company to set the customer charge accordingly. In addition, the Department finds to price the peak demand charge at a higher rate than the off-peak demand charge the Company must shift $120,000 in base revenues from the off-peak to the peak season. The Department further directs the Company to set the demand charge to collect the remaining class revenue responsibility as specified on Schedule 10.

7. Rate G-51: C&I Low Use, High Load Factor

The G-51 rate is available to C&I customers whose maximum hourly meter capacity is between zero and 500 cubic feet per hour and whose metered use in the most recent peak period of November through April is less than 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. BGC-94, at 10). The Company proposed to increase the monthly customer charge from $20.00 to $25.00 (Exh. BGC-75, at 18). The proposed commodity charge during the peak season is $0.4071

per therm for the first 150 therms consumed and $0.1500 for each additional therm. The proposed commodity charge during the off-peak season is $0.4071 per therm for the first 60 therms consumed and $0.1500 for each additional therm. None of the intervenors commented on the Company's proposed design of Rate G-51.

According to the Company's MCS, the total peak season marginal cost for Rate G-51 is $0.1288 (Exh. BGC-114, Sch. 11, at 1). Based on a review of marginal costs and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $22.00 monthly customer charge and a $0.1500 tailblock rate for the peak and off-peak seasons respectively, satisfies continuity goals and produces bill impacts that are moderate and reasonable. Therefore, the Department directs the Company to set those charges accordingly. The Department also directs the Company to set the breakpoints between headblock and tailblock at 150 and 60 therms in the peak and off-peak seasons, respectively, and to set the seasonal headblock rates at the same charge in order to collect the remaining class revenue responsibility as specified on Schedule 10.

8. Rate G-52: C&I Medium Use, High Load Factor

The G-52 rate is available to C&I customers whose maximum hourly meter capacity is between 501 and 1,500 cubic feet per hour and whose metered use in the most recent peak period of November through April is less than 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. BGC-94, at 11). The Company proposed to increase the monthly customer charge from $35.00 to $45.00 (Exh. BGC-75, at 18). The proposed commodity charge during the peak season is $0.2551 per therm for the first 520 therms consumed and $0.1500 for each additional therm (Exh. BGC-94, at 11). The proposed commodity charge during the off-peak season is

$0.2551 per therm for the first 400 therms consumed and $0.1500 for each additional therm (id.). None of the intervenors commented on the Company's proposed design of Rate G-52.

According to the Company's MCS, the total peak season marginal cost for rate G-52 is $0.1146 per therm (Exh. BGC-114, Sch. 11, at 1). Based on a review of the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $38.50 monthly customer charge and a $0.1500 tailblock rate for the peak and off-peak seasons, satisfies continuity goals and produces bill impacts that are moderate and reasonable. Therefore, the Department directs the Company to set those charges accordingly. The Department further directs the Company to set the breakpoints between headblock and tailblock at 520 and 400 therms in the peak and off-peak seasons, respectively, and to set the seasonal headblock rates to collect the remaining class revenue responsibility as specified on Schedule 10.

9. Rate G-53: C&I High Use, High Load Factor

The G-53 rate is available to C&I customers whose maximum hourly meter capacity is between 1,501 and 12,000 cubic feet per hour and whose metered use in the most recent peak period of November through April is less than 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. BGC-94, at 12).

The Company proposed to increase the monthly customer charge from $100.00 to $125.00 (Exh. BGC-75, at 18). The proposed commodity charge during the peak season is $0.2664 per therm for the first 1,500 therms consumed and $0.1500 for each additional therm (Exh. BGC-94, at 12). The proposed commodity charge during the off-peak season is $0.1412 for all therms consumed (id.). None of the intervenors commented on the Company's proposed design of Rate G-53.

According to the Company's MCS, the total peak season marginal cost for rate G-53 is \$0.1365 per therm (Exh. BGC-114, Sch. 11, at 1). Based on a review of marginal costs and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a \$110.00 monthly customer charge and a \$0.1500 tailblock rate for the peak season and a flat commodity charge for the off-peak season, satisfies continuity goals and produces bill impacts that are moderate and reasonable. Therefore, the Department directs the Company to set those charges accordingly. The Department also directs the Company to set the breakpoint between headblock and tailblock at 1,500 therms in the peak season, and to set the flat off-peak commodity rate so as to collect the remaining class revenue responsibility as specified on Schedule 10.

10. Rate G-54 & Rate G-55: C&I Extra-High Use, High Load Factor

a. The Company's Proposal

The G-54 rate is available to C&I customers whose maximum hourly meter capacity is greater than 12,000 cubic feet per hour and whose metered use in the most recent peak period of November through April is less than 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. BGC-94, at 13). Currently, the G-54 class rate structure is based on a customer charge and an estimated maximum demand charge (Exh. BGC-75, at 18).

The Company proposed to return Rate G-44 to a volumetric billing basis, based on its assertion that customers find the current demand billing method confusing (id.; Tr. 6, at 100). In addition, the Company proposed to: (1) increase the monthly customer charge from \$400.00 to \$450.00 (Exh. BGC-83, at 1); and (2) set the commodity charge for the

peak and off-peak seasons at $0.1702 per therm for all therms consumed (Exh. BGC-94, at 8).

The Company also proposed to create a new rate class, G-55 (Exh. BGC-75, at 19). According to the Company's proposal, customers who are currently served on Rate G-54 and whose annual usage is greater than 25,000 MCF would be served on Rate G-55 (id.). The Company proposed to design Rate G-55 on a metered demand basis; that is, their monthly billing determinant would be the highest daily usage in the billing month (id.). Also, the Company proposed to install telemetry devices to record the daily demand for those G-55 customers who do not currently have them (id.). The Company proposed to include the cost of these meters in the class revenue requirement (id.; Exh. BGC-110).

b. Positions of the Parties

i. DOER and NEEC

DOER and NEEC argue that the Company's proposed rates G-54 and G-55 have unacceptably large variations in their impact on customers and, therefore, violate the Department's continuity goal (DOER Brief at 90; NEEC Brief at 3-5). Accordingly, DOER and NEEC state that the Department should reject the Company's proposal and, instead, should recombine Rates G-54 and G-55 under the current rate design, as shown in Record Request DPU-51 (DOER Brief at 90, NEEC Brief at 5-6).

ii. The Company

Based on the adverse bill impacts associated with the Company's proposed design of rates G-54 and G-55, the Company proposes to withdraw its initial proposal for these two rates (Company Brief at 87). Instead, the Company proposes a single G-54 Rate, designed according to the method currently in effect (id.).

c. Analysis and Findings

Based on a review of seasonal and annual bill impacts on customers, the Department agrees with DOER, NEEC and the Company that the Company's proposed design of rates G-54 and G-55 produces adverse bill impacts. Accordingly, the Department directs the Company to establish a single G-54 Rate, designed according to the method currently in effect for Rate G-54. This alternative is supported on brief by DOER, NEEC, and the Company.

Based on a review of the bill impacts on customers, as well as the marginal and embedded costs, the Department finds that a rate designed with a $450.00 monthly customer charge moves the customer charge closer to its embedded cost and satisfies the Department's continuity goal. Therefore, the Department directs the Company to set the customer charge accordingly. In addition, the Department finds to price the peak demand charge at a higher rate than the off-peak demand charge the Company must shift $175,000 in base revenues from the off-peak to the peak season. The Department further directs the Company to set the demand charge to collect the remaining class revenue responsibility as specified on Schedule 10.

11. The G-60-Series Rates

The G-60 series rates are available to C&I customers whose metered use in the most recent peak period of November through April is less than or equal to 20 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. BGC-94, at 15-17). The Company proposed to set the customer and commodity charges for rates G-61, G-62, and G-63 identical to the charges it proposed for rates G-51, G-52, and G-53, respectively (Exh. BGC-75, at 18). Boston Gas stated that it did this

because rates based on its cost studies for the G-60 series customers would have been illogical (Exh. BGC-75, at 18). As examples, the Company stated that the peak period marginal costs for the summer load factor G-60 class are above the peak period marginal costs developed for the high load factor class (id.). The Company asserted that these distortions may be the result of some outlier among the limited number of G-60-series customers (id.). Accordingly, the Company maintained that use of the G-60 series studies to develop rates would send price signals that clearly would be inefficient (id.). Also, the Company contended that combining the G-60 series with the G-50 series has minimal impact on the bills of the G-50 series customers and allows it to develop rational rates for the G-60-series customers (id.). No intervenors commented on the Company's proposed G-60 series rates.

The Department agrees with the Company that use of the G-60-series studies to develop rates would send inefficient price signals, and that combining these classes has minimal impact on customers's bills. Accordingly, the Department finds it acceptable to set the customer and commodity charges for rates G-61, G-62, and G-63 identical to the charges approved by the Department for rates G-51, G-52, and G-53, respectively.

12. Rate G-7: Street Lighting

Rate G-7 is available to any street lighting customer (Exh. BGC-94, at 18). The Company proposed a two-part rate consisting of an annual fixed charge of $138.84 per lamp and running charges of 1.98 and 0.63 cents per hour for the peak and off-peak periods, respectively (id.).

To determine the proposed rates, the Company first calculated the total number of lamps, with and without clocks, and computed the total running hours per season for all

lamps (Exh. BGC-82, at 14). Next, the Company divided the total class annual use by the total annual running hours of all lamps to derive an estimate of the therm use per lamp per hour (id.). The therm use per lamp per hour was then multiplied by the peak and off- peak marginal energy costs, taken from the Company's MCS, to arrive at the estimates for the seasonal hourly running charges (id.). Multiplying the seasonal hourly running charges by the corresponding total hours of operations, the Company arrived at the peak and off-peak energy revenues (id.). The sum of these revenues was then subtracted from the total class revenue requirements, and the difference was divided by the total number of lamps, giving the fixed annual charge per lamp (id.).

Because this service is unmetered, and based upon the principle of simplicity in rate design, the Department finds the Company's method for determining its proposed rate to be acceptable. Accordingly, the Department directs the Company in its compliance filing to set a monthly fixed charge that would recover the class's revenue requirements discussed above.

13. Rate G-17: Outdoor Gas Lighting

The G-17 rate is available to all customers for outdoor gas lighting where a standard gas light on private property cannot be metered along with the gas used for other purposes by the customer (Exh. BGC-94, at 19). The Company proposed a peak and off-peak charge of $36.83 and $28.80 per month, respectively (id.).

The Company determined these seasonal monthly charges by first determining the therm use per hour per lamp by dividing the class total annual therm use by the total annual running hours of all the lamps (Exh. BGC-82, at 14). The result was multiplied by the peak and off-peak marginal energy costs, based on the Company's MCS, to derive estimates of the marginal commodity costs per hour (id.). These seasonal marginal commodity costs per hour

multiplied by the running hours per lamp, provided the estimate of the monthly energy cost per lamp (id.). The Company then computed the peak and off-peak energy revenues by multiplying the estimated seasonal marginal energy cost per hour by the total peak and off-peak running hours of all the lamps (id.). The sum of the seasonal energy revenues was subtracted from the class revenue requirement, and the difference was divided by the total number of lamps, resulting in an estimate of the annual fixed charge per lamp (id.). The annual fixed charge per lamp was then added to the seasonal monthly energy cost per lamp, resulting in the proposed monthly charge (id.).

Because this service is unmetered, and based upon the principle of simplicity in rate design, the Department finds the Company's method for determining its proposed rate to be acceptable. Accordingly, the Department directs the Company in its compliance filing to set a monthly fixed charge for the peak and off-peak season that would recover the class's revenue requirements as shown in Schedule 10 and the revenue allocated to this class from Rate G-17.

VII. PROPOSED CHANGES TO THE COST OF GAS ADJUSTMENT CLAUSE

A. The Company's Proposal

In Boston Gas Company, D.P.U. 93-60 (1993), the Company revised its CGAC so that all gas costs were removed from base rates and were collected through residential and C&I specific factors in the CGAC. In the instant case, Boston Gas has proposed to amend its CGAC currently in effect to exclude all charges related to local distribution costs (Exh. BGC-75, at 28). Specifically, the Company would exclude from its CGAC demand side management costs (Residential Energy Savings Programs and Low Income Energy Savings Programs), related working capital and reconciliation adjustments, environmental

response costs related to manufactured gas plants, and FERC Order 636 pipeline transition costs (id.). The Company proposed to recover these costs from all core sales and transportation customers through the proposed Local Distribution Adjustment Clause ("LDAC") (id., at 29). The proposed LDAC defines the residential and commercial/industrial Local Distribution Adjustment Factors ("LDAFs"), which Boston Gas would apply on a per-therm basis (id.). Additionally, the Company proposed to amend its CGAC to remove all capacity credits related to interruptible transportation service, and submitted that these credits be returned to customers in the form of a buydown to base rates, with one exception: margins earned on interruptible transportation service provided to Distrigas[75] would continue to be returned to core sales and transportation customers through the LDAC (id.).

The Company indicated that these proposed changes were made to separate fully cost adjustments related to the Company's merchant service from downstream local distribution costs and credits (id.). The Company maintained that under its proposed CGAC, upstream capacity and commodity costs, credits related to the sale of gas, production and storage used for supply, and gas acquisition costs would apply to firm core gas sales (id.). The Company further stated that credit adjustments associated with the more efficient use of upstream capacity, such as capacity release, interruptible sales at the city gate, and sales for resale would accrue to CGAC sales customers, and that all costs and credit adjustments related to local distribution service would be passed through to all core sales and transportation

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75 Under FERC's certificate of authority for service to Distrigas, Boston Gas is required to flow back to core customers all margins associated with this service. The Company's proposal regarding IT credits is discussed in Section IX.A.1, below.

throughput by means of the proposed LDAC factor (id., at 30). No parties commented on the Company's proposal.

B. Analysis and Findings

In Bay State Gas Company, D.P.U. 95-104 (1995), the Department approved a settlement which provided that Bay State remove from its CGAC costs associated with DSM programs and related working capital and reconciliation adjustments, environmental remediation costs, FERC Order 636 transition costs, and non-core sales margins allocated to distribution services, and collect these costs through an LDAC.[76] The Company's proposal to exclude from its CGAC DSM costs, related working capital and reconciliation adjustments, environmental response costs related to manufactured gas plants, and FERC Order 636 pipeline transition costs is consistent with the Department's finding in D.P.U. 95-104 as it relates to Bay State's LDAC.

The Department finds Boston Gas' LDAC proposal to be a rational method to collect non-gas-related costs, especially in light of the Company's unbundling efforts. However, the Department is rejecting the Company's proposed buyout of its IT market. See Section IX.A.3, below. Accordingly, the Department directs the Company to flow back IT margins to core and transportation customers through the LDAC.

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[76] While the Department's Order in D.P.U. 95-104 makes reference to Bay State's Distribution Adjustment Cost Clause, the Department is seeking to standardize terms used by utility companies. Accordingly, the Department directs LDCs to use the term "Local Distribution Adjustment Clause."

VIII. DEMAND-SIDE MANAGEMENT

A. Introduction

The Company's current DSM programs were filed with the Department on March 22, 1996. In Boston Gas Company, D.P.U. 94-109 (Phase II), at 1, Interim Order on Demand-Side Management (April 26, 1996), the Department approved the Company's proposal to eliminate certain energy conservation measures from its residential Energy Savings Plan program because they were not cost-effective.[77] In addition, the Department rejected the Company's proposal to eliminate its Commercial and Industrial ("C&I") and Multifamily DSM programs that were approved in Boston Gas Company, D.P.U. 94-21 (1994). D.P.U. 94-109 (Phase II) at 2. Further, the Department ordered the Company to extend the C&I and Multifamily programs until the Company's PBR and unbundling plan is implemented. Id.

B. The Company's Proposal

1. C&I and Multifamily Programs

The Company proposed to extend its existing C&I and Multifamily DSM programs through April 30, 1997 (Tr. 13, at 9-10). The Company also proposed to terminate these programs after such date (Exh. BGC-35, at 2). The Company stated that this decision is based on the results of a new cost-effectiveness test (Exh. AG-41).

In addition, Boston Gas proposed to offer its C&I customers competitively-priced energy service offerings which would be paid for by the participants who choose the services

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77 The Department notes that the approved residential Energy Savings Plan includes a budget of $1 million for the period May 1, 1996 through April 30, 1997, a penetration target of 5,600 customers to be served, and a benefit-cost ratio of 1.25 (Exh. BGC-35, at 3-4).

(Exh. BGC-34, at 3; RR-DPU-17, at 3). The program, entitled C&I "Energy Services Program," would include the following: (1) facilitating partnerships between large C&I customers and third-party Energy Service Companies ("ESCO") for delivery of energy-related products at no cost to non-participating customers; and (2) offering energy efficiency products and services at competitive prices to small and medium C&I customers (Exh. BGC-34, at 4-5; RR-DPU-17, at 3).[78] The Company did not request recovery of costs or lost margins for these energy efficiency services, and the Company proposed that revenues be included in the competitive services basket (Exh. BGC-34, at 5-6). Boston Gas stated that its performance in providing these competitive products and services should be evaluated using market-based indicators, such as customer satisfaction, completed jobs, and quality control, rather than by achievement of energy savings (id. at 10).

The Company identified $19,416 in expenses associated with the development of its competitive DSM services (RR-DPU-55). In addition, the Company stated that it will continue to track employee time spent on the development of these services, and will establish appropriate accounting procedures to track all associated expenses and revenues (Exh. DPU-54; Tr. 8, at 97-104).

2. Residential Programs

The Company proposed the following elements in its existing residential DSM program. First, the Company's Energy Savings Plan, which consists of measures meeting the traditional avoided cost test for cost-effectiveness (i.e., domestic hot water measures and clock thermostats), would be delivered as an add-on to the existing Energy Conservation

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78 The Department notes that Boston Gas did not specify the number of C&I customers it intends to target, the number of services it intends to provide, or a program budget.

Services ("ECS") program, and penetration targets would be established pursuant to the ECS program (Exhs. BGC-34, at 6, 10; DOER-56).[79] The measures would be provided at no direct cost to the customer, and the Company proposed to recover lost margins associated with these measures (Exh. BGC-34, at 6). Second, the Company proposed to provide energy efficiency products to all residential customers at competitive prices via its Energy Efficient Products offering (id. at 7). The Company did not request recovery of costs or lost margins for the sale of these products, and the Company proposed that revenues from these sales be included in the competitive services basket[80] (id.). Boston Gas stated that its performance in providing these competitive products and services should be evaluated using market-based indicators, such as customer satisfaction, completed jobs, and quality control, rather than by the amount of energy savings achieved (id. at 10).

Third, the Company proposed to provide fully subsidized DSM measures (i.e., the installation of attic and/or wall insulation) to low-income customers even though this program is not cost-justified based on traditional avoided cost tests (id. at 7-9). The Company provided an annual budget of $2,193,600 for the low-income program for the next five years, and indicated that the costs would be recovered from all customers through the LDAC (id.; Exhs. BGC-117; BGC-91; BGC-93).[81] The Company did not seek any incentives for implementing this program, but proposed to recover associated lost margins (Exh. BGC-34, at 8). The Company explained that those customers who qualify for its heating subsidized

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79 The Department notes that the existing Energy Savings Plan is already combined with the Company's ECS program (Exh. DOER-56).

80 See Section XI.C.1.c for a description of the competitive services basket.

81 See Section VII.A for a description of the LDAC.

contemplates that the Company should be rewarded for any accomplishments and penalized for any failures within the parameters of the PBR scheme, if one is approved (id.).

2. Low-Income Intervenors

The Low-Income Intervenors argue that the proposed Low-Income Energy Efficiency Program is necessary and appropriate for several reasons: (1) low-income customer efficiency needs are distinct from those of non-low-income customers; (2) low-income customers will not be acquiring energy efficiency services through the competitive market; (3) market transformation initiatives[84] will not reach this group of customers; and (4) the program is consistent with the Department's policies enunciated in Electric Industry Restructuring, D.P.U. 96-100 (1996) (Low-Income Intervenors Brief at 4-6; Exh. LII-1, at 3). The Low-Income Intervenors state that the fundamental aspects of the Company's Low-Income Energy Efficiency Program are excellent, including the budget level, length of the program, energy conservation measures ("ECM") to be delivered, and administration plan, including the use of a lead administrative vendor (Low-Income Intervenors Brief at 1).

The Low-Income Intervenors conclude that it makes sense for the Company to work with DOE WAP subgrantees to adopt the DOE-approved weatherization audit as the basic tool for screening measures (id. at 3-4). The Low-Income Intervenors note that Boston Gas has a contract with a vendor through the middle of 1997 to deliver DSM services, including audits, and recommends phasing in the use of the DOE audit when this contract expires (id. at 4).

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[84] In D.P.U. 96-100, Attachment A, Proposed Rules Governing the Restructuring of the Electric Industry, 220 C.M.R. § 11.09, the Department defined market transformation initiatives as strategic efforts to offset market failures and to induce lasting structural or behavioral changes that result in increases in the adoption or penetration of energy efficient technologies or practices.

3. DOER

DOER contends that the Company's DSM proposal to terminate its existing monopoly C&I and Multifamily DSM programs represents an "abrupt cessation" of these programs and is inconsistent with the Department's stated goals of an orderly transition of DSM services to a competitive energy market (DOER Brief at 98-99, citing Electric Industry Restructuring, D.P.U. 95-30 (1995); DOER Reply Brief at 25). DOER argues that the Company's proposed market-driven C&I program, which the Company claims would replace the existing C&I and Multifamily DSM programs, is in fact intended to increase throughput and improve the Company's profitability (DOER Brief at 100, 108-112). DOER concludes that the competitive C&I program provides no guarantee that energy efficient products will be installed or that market barriers to energy efficient products will be addressed, and recommends that the Department direct Boston Gas to submit a modified DSM proposal (id., citing RR-DPU-17; Tr. 13, at 62, 69, 81-82; Tr. 15, at 69, 88, 93, 96; DOER Reply Brief at 25).

DOER also contends that the Company's proposed residential Energy Efficient Product Offering is inconsistent with the Department's stated goal for maintaining DSM programs during the transition toward a competitive energy service market (DOER Brief at 101). Specifically, DOER argues that, although the Company indicates that it will offer a competitive residential program, it has provided no specific information supporting this intention, and that a simple scaling back of existing retrofit programs is not sufficient to maintain DSM programs during the transition toward competitive markets (id.).

DOER notes that Boston Gas's C&I Energy Services Program would effectively eliminate the Department's ability to regulate and evaluate the Company's C&I DSM

programs through the transition period, and that this would be in direct conflict with the Department's Order in D.P.U. 95-30, where the Department recognized that some continuing level of regulation will be necessary to mitigate the effect of market failures (id. at 101-104, 114-116, citing D.P.U. 95-30, at 65). DOER also argues that if the Department approves the C&I Energy Services Program, the Company will have an unfair competitive advantage over other energy service providers (id. at 113). Accordingly, DOER recommends that if the Department permits the Company to offer the C&I Energy Services Program and capitalize on its market position, then non-utility energy service providers must have comparable access to customer information (id. at 114). DOER also recommends that the Department should require the Company to (1) track energy impacts of competitive programs offered during the transition, and (2) evaluate whether competitive programs are overcoming financial, technical, and informational barriers to energy efficiency services, or assisting in any way to transform the market for energy efficiency measures and services (id. at 116).

DOER argues that the Company's cost-effectiveness analysis in fact showed that the majority of measures in the average C&I and Multifamily programs were cost-effective, but that the Company did not perform any analysis to determine whether to design a program using these cost-effective measures (id., citing Exh. AG-41; Tr. 13, at 42). Further, DOER asserts that Boston Gas's analysis of measures for small C&I customers was flawed, because only the benefit side of the updated screening analysis was revised, and that costs for some of these measures have declined (id., citing Tr. 13, at 53).

DOER recommends that the Company be required to file a five-year energy efficiency plan for all customer sectors well before the expiration of its current programs, which addresses the following areas: (1) an updated cost-effectiveness evaluation and commitment

to continue to provide cost-effective measures through the transition; (2) promotion of selected efficiency products that can be moved from moderate levels of market acceptance to high levels; (3) a description of market transformation initiatives that will be undertaken through the transition period; and (4) budget levels that represent a commitment to energy conservation (id. at 104; DOER Reply Brief at 26-27).

Regarding the development of the proposed competitive C&I Energy Services Program using the ratepayer-funded DSM infrastructure, DOER argues that if these development costs, including work done by the customer research group, are not removed from the Company's cast-off rates, then the cost to develop these programs is being subsidized by ratepayers (DOER Brief at 104-106; Tr. 15, at 95; DOER Reply Brief at 27). DOER recommends that the Department require the Company to compensate ratepayers fairly for its use of existing DSM infrastructure, and to remove from its cost of service the percentage of DSM-related costs Boston Gas incurred to provide competitive services (DOER Brief at 108; DOER Reply Brief at 28).

4. NEEC

NEEC argues that Boston Gas's proposal to abruptly eliminate its C&I and Multifamily DSM and to reduce its residential program is inconsistent with Department directives in D.P.U. 96-100 because the proposal does not constitute a gradual shift in energy efficiency services which compete in the open market, does not address continuing market barriers, and may damage the energy efficiency industry (NEEC Brief at 2). NEEC urges the Department to direct the Company to develop, in collaboration with interested parties, a five-year energy efficiency plan which represents a gradual transition, addresses market barriers and market transformation, and supports the energy efficiency industry (id.).

NEEC contends that the Company's proposed energy services programs are not a substitute for regulated DSM programs because (1) the programs are not yet developed and there is not enough information to evaluate them; (2) the Company will be free to change the programs since they are proposed as competitive programs; and (3) the competitive programs are designed to accomplish goals different from those of regulated DSM, which provides energy efficiency products and services that the market will not provide due to market barriers (id. at 3). NEEC further argues that the Company's proposed competitive energy services programs are potentially anticompetitive, because the programs would be in direct competition with non-monopoly energy service providers, and would have competitive advantages (id. at 4). NEEC recommends that the Department explore anticompetitive issues at a time when the Company's proposal is more fully developed (id.).

NEEC supports Boston Gas's proposal to extend its current C&I and multifamily programs through April 30, 1997, based on the following: (1) the Company's proposal to terminate the monopoly DSM programs is inconsistent with D.P.U. 96-100; (2) the program extension is not a gradual shift and transition of DSM required by the Department but maintains the programs while the Company and interested parties reach agreement on a new set of monopoly DSM programs; and (3) during the extension, the Company would implement the current DSM programs at the approved budget levels (NEEC Reply Brief at 1-2.

Finally, NEEC argues that the Company's cost-effectiveness analysis does not support termination of C&I and Multifamily DSM programs, and does not satisfy the Company's obligation to develop and offer DSM programs in a changing environment (id. at 2-3).

NEEC recommends that the Company design programs to address market barriers to energy efficiency (id. at 3).

5. The Company

The Company reaffirms its position that it will continue to offer only those existing monopoly DSM programs that are shown to be cost-effective (Company Brief at 150). Boston Gas states that it has submitted evidence supporting the Company's proposal to discontinue offering its C&I and Multifamily DSM programs,[85] that these programs should no longer be offered as ratepayer-subsidized monopoly services after the April 1997 extension, and that it is currently developing competitive DSM programs (id. at 150-151). The Company explained that the extension of the programs until April 1997 will ensure an orderly transition to a competitive environment (id. at 151).

The Company states that NEEC's proposal for a C&I and Multifamily market transformation program could serve as a transition program for these sectors, and that Boston Gas intends to hold a series of technical sessions and workshops between August 16, 1996 and March 1, 1997, designed to reach a mediated, rather than a litigated agreement on this program (Tr. 13, at 10). The Company further states that it is undertaking discussions with NEEC and a preliminary program outline has been drafted as an extension of its approved regulated C&I and Multifamily DSM programs (Company Brief at 151).

[85] The Company explains that this decision was based on the results of a new screening test, where three out of four C&I customers (i.e., those qualifying for the small C&I program) would be eligible to receive only one DSM measure (i.e., hot water consumption reduction) (Company Brief at 150). The Company argues that reducing small C&I customers's hot water consumption would not produce enough savings to justify the continuation of all C&I programs (id.).

Regarding its residential Low-Income Energy Savings Program, the Company states that it is committed to providing a subsidized energy efficiency program for low-income customers (Company Brief at 152-153, citing Exhs. BGC-91; BGC-93; BGC-117). The Company requests that this program be approved with a few minor enhancements that have been developed with interested parties (id. at 153). For administrative efficiency, the Company proposes that one entity perform the role of lead vendor (id.). In addition, the Company agrees with the method proposed by the Low-Income Intervenors for tracking the use of funds and implementation results, allocating budgets and number of jobs, and developing an implementation schedule (id., citing Tr. 13, at 124, 149-155, 161). The Company has also agreed to augment its original program design to include funding for heating system replacements and air sealing, including blower door testing, and that its financial contribution would be limited to the incremental cost above the state-funded "Heart-WAP" program levels[86] for gas-to-gas heating system replacements (id. at 154, citing Tr. 13, at 130, 138).

The Company reiterates its intent to recover lost margins associated with the Low-Income Energy Savings Program using the method approved in Boston Gas Company, D.P.U. 93-108, Boston Gas Company, D.P.U. 94-15 for insulation measures, and the method approved for Berkshire Gas Company in D.P.U. 94-15 for air sealing (Company Brief at 154). The Company explains that it will not seek recovery of lost margins for

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[86] The Low-Income Intervenors state that the Heart-WAP program, which is funded from the Department of Health and Humans Services's fuel-assistance program, provides heating system replacements, repairs, and tune-ups to qualified low-income customers (Tr. 13, at 129).

incremental heating system replacements, since the Department has not approved a method for estimating energy savings from these installations (id.).

Regarding the $19,416 expended by the Company to research and develop its competitive DSM programs in 1996, the Company states that its shareholders will bear these costs (id. at 155, citing Exh. BGC-34, at 5-6). The Company explains that it will track all expenses and revenues associated with competitive DSM services, and will establish appropriate accounting procedures to accomplish this task as time allows (id., citing Tr. 8, at 102-103).

E. Analysis and Findings

In Boston Gas Company, D.P.U. 94-109 (Phase II), at 6-7 Interim Order on Gas Demand Side Management (February 23, 1996), the Department stated that the transition to market-driven DSM programs means that utilities will assume a different role in designing and implementing certain DSM programs, and third-party providers may supply many of these services. The Department concluded that for future DSM programs to be sustainable in an increasingly competitive environment, they must be designed and implemented with these market changes in mind. Id. at 7. The Department also articulated the following filing guidelines to apply to the Company's future DSM programs: (1) submission of proposed DSM programs that are generally consistent with today's increasingly competitive market conditions; (2) development of evaluation strategies that will facilitate a more timely, focused review of the effectiveness of the Company's DSM programs; (3) consideration, where appropriate, of a variety of performance criteria to gauge Company performance in its delivery of energy services, including the delivery of DSM-related services; and

(4) participation in settlement discussions with all interested parties regarding its future DSM programs. Id. at 8-9.

In D.P.U. 95-30, at 44, the Department stated that utility-sponsored energy efficiency programs should remain in effect during the transition toward a more competitive energy supply market so that the fledgling energy efficiency service industry might have a meaningful opportunity to compete with other electric services in the future. In Western Massachusetts Electric Company, D.P.U. 96-8-CC at 7 (1996), the Department stated that the transition from electric company-sponsored DSM programs to energy efficiency services that compete effectively in an open market will best be accomplished through a gradual shift rather than through an abrupt cessation of traditional electric company-sponsored DSM.

In D.P.U. 96-100, at 67, the Department proposed that each investor-owned electric company file a plan that includes the movement away from traditional retrofit programs toward market-driven programs over a five-year period. See Colonial Gas Company, D.P.U. 96-18, at 59 (1996). In addition, the Department recognized that providing low-income customers with energy efficiency services is one way to address the inability of these customers to purchase these services and reduce the inefficiencies of low-income housing stock. D.P.U. 96-100, at 65 n.43.

Further, the Department stated that utilities's long-term role in providing certain services to the energy efficiency market may include the following responsibilities: supporting market transformation activities on a regional or national level; providing technical assistance; providing technical and customer information; using existing relationships with retail customers to disseminate energy efficiency information to customers and other information to the market; providing referrals to and coordinating with sources of

private financing; coordinating with energy efficiency experts to identify potential energy savings; and supporting research and development of energy efficiency technologies in the private sector. Id. at 66 n.45. The Department also proposed that transition programs include a customer information component that would educate customers about the benefits of energy efficiency services and increase customer demand for technologies to control energy use. Id. at 67.

With respect to the Company's proposal to extend its existing C&I and Multifamily DSM programs through April 30, 1997, and to terminate them after such date, the Department finds that this is appropriate as long as the purpose of the program extension is to maintain the Company's existing C&I and Multifamily DSM programs while the Company and other interested parties reach agreement on a new set of market transformation DSM programs to be implemented after April 30, 1997. However, the Department shares DOER's and NEEC's concern that the Company's proposed residential Energy Efficient Product Offerings and C&I Energy Services Program will not address certain market barriers during the transition toward a more competitive energy service market. The record shows that both the Company and interested parties are willing to work together through mediation to develop programs that would address these barriers during the transition to competitive markets, and the Department strongly encourages these negotiations.

Accordingly, the Department finds that the development and implementation of such market transformation programs before May 1, 1997, would be consistent with the Department's recent directives to ensure a smooth transition toward more competitive energy services while addressing remaining market barriers, transforming markets, and supporting the energy efficiency industry. Therefore, the Department approves the Company's plan to

extend its existing C&I and Multifamily DSM programs through April 30, 1997, and to terminate them after such date.[87] In addition, the Department directs the Company to file a proposal for its participation in energy efficiency market transformation initiatives for the Department's review by March 1, 1997. The Department expects this filing to include a description of proposed market transformation initiatives appropriate for all customer sectors, and to be consistent with the Department's guidelines set forth in D.P.U. 94-109 (Phase II) and D.P.U. 96-100. The Department also expects that these market transformation initiatives will include a strong education component that informs customers about energy efficient products, service and financing options available from the Company or third-party providers. In addition, this filing should include a time frame reflective of the Company's transition to full unbundling, budget levels that represent a commitment to energy conservation, and a cost recovery and program evaluation strategy consistent with recent Department precedent.

Regarding the Company's competitive DSM programs, the Department acknowledges Boston Gas's efforts to design residential and C&I energy efficiency programs consistent with an increasingly competitive energy service market. In addition, the Department recognizes that our approval and oversight of these programs is not necessary unless expenses attributable to these programs are subsidized by ratepayers or the implementation of these programs include anticompetitive practices. With regard to these latter two points, the Department shares (1) DOER's concern that ratepayer funds were used to develop these programs, and (2) DOER's and NEEC's concern that Boston Gas may be in a superior market position to offer these competitive services. At a minimum, the Department is

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87 The Department expects the Company to fulfill any obligations committed to during this extension, including installation of ECM's, financial agreements, or any other contractual arrangement entered in good faith.

concerned that an appropriate accounting system has not yet been established to track the expenses and revenues attributable to these programs. The Department finds that although Boston Gas claims that only shareholders will bear the competitive DSM program costs, the Company has not demonstrated that it has properly accounted for these program development costs. Accordingly, the Department finds that the Company should develop and implement a cost accounting system for its competitive DSM programs by March 1, 1997. In addition, the Department finds that the Company should demonstrate that it has appropriately accounted for these program development costs, and the Company is directed to do so in its 1997 off-peak CGAC filing. Specifically, if these costs have been expensed to the Company's traditional DSM program expense accounts, such costs should now be credited to sales customers through the appropriate Conservation Charges.

Regarding the concern raised by DOER and NEEC pertaining to potential anticompetitive behavior, the Department has proposed rules to establish the standards of conduct governing the relationship between natural gas LDCs and their competitive affiliates.[88] Order to Consolidate Standards of Conduct Rulemaking, D.P.U. 96-44 (November 27, 1996). As proposed, these rules would apply to the regulated utility's relationship with any competitive affiliate, and would prohibit a regulated utility from providing any product or service (except those of general corporate nature) to a competitive affiliate unless that product or service is offered to the market as a whole. Id. at 3. In addition, the proposed rules contain a dispute resolution procedure. Id., Proposed Rules 220 C.M.R. § 12.03(15). The Company's proposal to offer competitive DSM services falls

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88 For a description of the term "competitive affiliate," see D.P.U. 96-44, Proposed Rules 220 C.M.R. § 12.02(4).

within the scope of these rules as proposed, and therefore, may be governed by the rules once adopted.

Regarding the Company's proposed Energy Savings Plan, the record indicates that under this Plan, the Company would continue to offer cost-effective DSM services similar to those services currently being provided through its existing residential DSM programs, which have been preapproved through April 1997. The record also indicates that under this plan, the Company would, on an annual basis, spend $1 million, reach approximately 5,600 customers, and submit an update as part of its annual price cap compliance filing. The Department finds that the proposed Energy Savings Plan is consistent with recent Department precedent, and is hereby approved. The Company should continue to implement the Energy Savings Plan for the duration of the five-year price cap plan, as long as it remains cost-effective, or until directed differently by the Department. Should evaluation results that reflect updated cost and benefit data indicate that this program is no longer cost-effective, the Company should redirect these program funds to market transformation initiatives for the residential sector that are agreed upon and approved by the Department for participation by the Company beginning May 1, 1997.

Regarding the Company's proposed Low-Income Energy Efficiency Program, the record shows agreement between the Company and the interested parties on the implementation schedule, program design, penetration targets, cost recovery strategy, evaluation plan, and administrative structure of this program. The record also shows that the Low-Income Intervenors recommend an additional $450,000 be added to the budget to accommodate certain program modifications. The Department finds that the program, as modified, is consistent with recent Department precedent. The Department also finds that it

is appropriate to adjust the budget upwards by $450,000 to reflect the additional expenses necessary to implement the modifications to the program, which all parties have agreed to. Accordingly, the Department approves the Company's proposed Low-Income Energy Efficiency Program, as modified, including a budget of $2.6 million to be recovered from all ratepayers through the LDAC.

The Department acknowledges that the primary goal in providing DSM programs for low-income customers is to reduce energy consumption and, therefore, customers's bills. To ensure program accountability, the Department directs the Company, as part of its 1998 DSM evaluation report, to evaluate whether the Low-Income Energy Savings Program recipients have achieved significant savings on their monthly bills as a result of this program. If the Company determines that this program does not result in significant benefits to low-income customers, the Company is directed to include as part of its 1998 evaluation report, an alternative program designed to mitigate the cost of service to low-income customers. The Department will revisit the merits of continuing this program at that time.

IX. INTERRUPTIBLE TRANSPORTATION

A. Buyout of IT Service By Boston Gas

1. The Company's Proposal

Under the Company's current treatment of IT, margins up to a set threshold are passed back to firm sales and transportation customers through the CGAC (D.P.U. 93-141-A at 64-65). Boston Gas is allowed to keep 25 percent of all margins over this threshold (id).

The Company has proposed to replace the margin-sharing arrangement with a permanent $2.0 million reduction in base rates by buying out or including this amount as an offset against the Company's proposed "cast-off" rates (Exh. BGC-3, at 40-41). The

Company determined this amount based on historical IT throughput and volumes for the period 1993 through 1995 (Exhs. BGC-3, at 41; BGC-7). The Company first determined an average annual throughput of 7,106,822 MMBtu, adjusted for sales to BECo, Distrigas, and customers converting to other services (Exhs. BGC-3 at 41; BGC-7). Based on the average transportation margin of $.2812 per MMBtu, less long-run marginal costs of $.1011 per MMBtu, the Company determined that the annual economic benefit to firm customers from IT service was $1,998,438 (Exh. BGC-7). Boston Gas projected that over the term of its PBR, the benefit to core customers associated with IT service would be $2.2 million (Exh. BGC-3, at 41).

2. Positions of the Parties

a. Attorney General

The Attorney General proposes that the value of a buyout be calculated on post-D.P.U. 93-141-A experience, since these are the volumes that have been affected by the margin-sharing mechanism currently in place (Attorney General Brief at 85). The Attorney General argues that because IT volumes have been growing very rapidly, any buyout should be postponed pending maturation of the IT market to ensure a full and fair value for the firm ratepayers (id. at 86)

b. DOER

DOER urges rejection of the proposed buyout and argues that it is inappropriate for the Department to consider the effects of the proposed buyout over the next five years, because the gas industry is entering its competitive era (DOER Brief at 91). According to DOER, IT demand and margins may increase significantly under competition (id.) Thus, DOER reasons that the Company could reap unacceptably high revenues if its proposal were

approved (id.). DOER believes that the Company's proposal would provide its shareholders with far larger returns than the Department anticipated in D.P.U. 93-141-A (id., citing D.P.U. 93-141-A at 63-65). DOER stated that any margin sharing arrangement resulting from IT service should be approved only if IT pricing were modified to permit service under a reasonable cost-based fixed rate, as requested by US Gypsum (id. at 92).

c. US Gypsum

US Gypsum alleges that the proposed buyout would further provide Boston Gas with the ability to "continue to use its monopoly power to exploit large gas users in Massachusetts" (US Gypsum Brief at 15). According to US Gypsum, the Company's exercise of monopoly power over the IT service on its system will be an increased deterrent to the development of new business in the Boston area (id. at 15). US Gypsum maintains that because IT service is relatively new and growing, valuation of IT is difficult, at best, and Boston Gas has severely undervalued this service (id. at 15). Consequently, US Gypsum urges the rejection of the proposed buyout (id. at 15).

d. TMG

TMG notes the distinct benefits that Boston Gas receives from its pricing discretion for IT in a gas market that, in other respects, is becoming increasingly competitive (TMG Brief at 43). TMG argues that, under the Company's proposal, ratepayers would secure no future returns from the IT market, and IT users would be denied competitive benefits, particularly as that market grows (id. at 43-44). TMG urges the Department to reject the proposed buyout, pending evolution of a competitive market (id. at 44).

e. <u>TEC</u>

TEC maintains that the Department should reject the Company's proposed IT buyout for the following reasons: (1) the Company has not demonstrated that its monopoly power over this distribution service would cease under its proposal; and (2) the Company's calculation of the value of IT service fails to account for the substantial growth that is anticipated in this market (TEC Brief at 10). TEC also urges rejection of a permanent sale and suggests renegotiation of any buyout value in a subsequent firm distribution rate case (<u>id.</u>).

f. <u>AIM</u>

AIM opposes the buyout of IT, claiming that it would bolster the utility's monopolistic "bargaining power" (AIM Brief at 17). AIM recommends conditioning any buyout on the implementation of a "fixed rate, fixed term" IT pricing alternative (id.).

g. <u>The Company</u>

The Company argues that the substitution of a buyout for margin sharing will encourage Boston Gas to market its capacity in a more competitive manner and will maximize the efficient use of its distribution system (Company Brief at 76). The Company states that it would continue to price its IT service on a value-of-service ("VOS") basis, and, consequently, would have increased incentives to meet competitive market prices if it received the rewards as well as the risks of serving a competitive market (Company Brief at 76). The Company notes that a margin-sharing mechanism has been in effect since November 1993, and claims that the IT market will not develop further without the added incentive provided by the buyout Boston Gas proposes (Company Brief at 77).

3. Analysis and Findings

The Department recognizes that the market for IT is undergoing rapid change. FERC has issued its Notice of Proposed Rulemaking ("NOPR") on eliminating the price cap on released pipeline capacity,[89] which may have a significant impact on access to IT service in Massachusetts. It is uncertain what level IT margins will reach in the future. Future IT margins could well rise above the test year levels, or could fall substantially below those levels. In order to ensure that the "cast off" rates established in this proceeding neither guarantee a substantial future revenue deficiency nor deprive ratepayers of the full benefit of future margins, we find that it would be premature for the Department to approve the Company's proposed buyout of its IT service. See Boston Gas Company, D.P.U. 1100, at 41.

The Department has approved the creation of an LDAC intended to recover certain local distribution-related costs currently recovered through the CGAC (see Section VII.B, above). Consistent with the treatment of IT margins associated with the Company's service to Distrigas in the LDAC, the Department finds that IT margins shall be flowed back to core sales and transportation customers through the LDAC approved by this Order, in the manner prescribed in D.P.U. 93-141-A.

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89 Secondary Market Transactions on Interstate Natural Gas Pipelines, Notice of Proposed Rulemaking, 61 Fed. Reg. 41,046 (1996) (to be codified at 18 C.F.R. pt. 284) (proposed August 7, 1996); Proposed Experimental Pilot Program to Relax the Price Cap for Secondary Market Transactions, 76 F.E.R.C. ¶ 61,120 (1996).

B. <u>IT Pricing</u>

1. <u>The Company's Proposal</u>

As indicated above, the Company currently prices its IT service on a VOS basis. Under its proposal to buy out the IT margin sharing contribution toward firm ratepayer cost responsibility, the Company would continue to use VOS in pricing IT service.

2. <u>Positions of the Parties</u>

a. <u>Attorney General</u>

The Attorney General recommends a bifurcated rate schedule by which a fixed IT rate, based on the average VOS of the past three years, would be applied for the nine-month interruptible period, while a VOS rate would apply during the three-month winter period (Attorney General Reply Brief at 46). This dual approach is intended to meet the concerns expressed by IT customers while providing a recognition of market forces during periods that are important to the firm ratepayers (<u>id.</u> at 45).

b. <u>DOER</u>

DOER argues that the Company's proposal will lead to higher rates (DOER Brief at 91) . DOER supports US Gypsum's position and proposes that the Company price its IT service to retain industrial load by offering IT customers a choice between cost-based fixed price IT and VOS rates (<u>id.</u> at 92, 97). According to DOER, the cost-based fixed price rate would be set above the marginal cost while the flexible VOS would be capped; both would provide a margin to the credit of core customers (<u>id.</u> at 97). DOER notes that none of the other LDC intervenors have raised the concern that modifications to IT pricing would be binding upon them, and that none of the other parties have suggested that this proceeding

would set a precedent for IT pricing by other Massachusetts utilities (DOER Reply Brief at 24).

c. US Gypsum

US Gypsum's witness, Mr. Cooper, testified that Boston Gas's use of VOS pricing permitted it to exercise its monopolistic market power over IT service (Tr. 17, at 33-34). He stated that the Company's continued use of VOS pricing might effectively discourage significant use of unbundling and further encourage an exodus of industrial companies from Massachusetts. US Gypsum proposes that the VOS rates for IT service be replaced by cost-based rates that are "significantly" below off-peak rates for quasi-firm services and reflect short term variable costs (US Gypsum Brief at 10).

d. TEC

TEC also supports a change from VOS to both fixed price and cost based ceiling options for IT rates (TEC Brief at 10-14; TEC Reply Brief at 6). In response to the Company's objections to considering IT pricing at this time, TEC notes that the Company raised the IT issue, the issue was the subject of US Gypsum's prefiled testimony, and a ruling would not adversely affect any LDC that is not a party to this proceeding (TEC Reply Brief at 7). Barring the fixed cost option, TEC proposes that the Department specifically eliminate a "state action" defense for such rates, thus leaving such negotiated rates open for antitrust challenges (TEC Brief at 13).

e. TMG

TMG believes that VOS pricing impedes entry into the competitive market (TMG Brief at 43). TMG asserts that the Company can exercise monopoly pricing power, because

IT sales are not capped by cost of service (TMG Brief at 42-43). Therefore, TMG advocates requiring the Company to adopt a cost of service-based IT rate (id. at 43).

f. AIM

AIM endorses the need for price predictability to keep manufacturers in Massachusetts (AIM Brief at 13). AIM urges a fixed rate for nine or twelve months (id. at 16). AIM also notes that this issue is properly before the Department in this proceeding (AIM Reply Brief at 4). Further, AIM notes that a change in IT pricing would be binding only on parties to the case (id. at 5).

g. ComGas

ComGas urges rejection of the effort to reconsider VOS pricing, because the issue was not noticed for resolution in this case and it would be unfair for the Department to address the issue in this Order (ComGas Reply Brief at 1-2).

h. Berkshire

Berkshire endorses the use of VOS pricing, but suggests that a ceiling, equal to firm transportation rates, would be appropriate (Berkshire Reply Brief at 5). In this context, Berkshire notes that if margin sharing was available, LDCs would have an incentive to maximize the margins from IT service (id.).

i. Essex

Essex notes that reconsideration of VOS pricing in this hearing would be procedurally untimely (Essex Reply Brief at 3). Essex notes that the issue was not included in either the initial filing or in the Hearing Officers's Ruling on Scope of Phase I. Consequently, Essex opposes consideration of this issue (id.).

j. The Company

Boston Gas states that, because the IT market is competitive and IT service is an alternative to other energy offerings and alternative energy prices, the Company cannot set rates (Company Brief at 78). The Company notes that competitive services are appropriately priced on a VOS basis (id. at 79-80). The Company indicates that the appropriateness of VOS pricing of IT has been recognized by the Department (id. at 79). The Company also states that due process considerations warrant rejection of efforts to change the manner of IT pricing, because (a) the issue was not identified in the Department's Notice of Order for this proceeding, (b) TEC's request for reconsideration was made on brief, and (c) many affected parties would not have received notice or had an opportunity to participate (id. at 80).

3. Analysis and Findings

The Department recognizes the need to address the issue of the pricing of IT. As we have stated above, access to IT service may be significantly affected by the disposition in FERC's proposal to eliminate the price cap on released pipeline capacity. In view of the impact of this ongoing federal proceeding and the effect the Department's disposition of the capacity assignment issues in Phase II may have on the IT market, the Department shall defer consideration of this issue pending the final disposition of the proposed capacity assignment program in Phase II.

X. CAPACITY ASSIGNMENT

A. Upstream Pipeline and Storage Capacity

1. The Company's Proposal

Boston Gas developed an unbundling plan which would require customers, or marketers working on behalf of customers, to take mandatory assignment of a pro rata share

of the Company's upstream pipeline and storage capacity contracts as well as a portion of the Company's Canadian supply contracts (Exhs. BGC-1, at 9-10; BGC-72, at 2).

Specifically, Boston Gas proposes to allow its eligible customers[90] to choose their gas merchant and have their allocated portion of upstream capacity assigned to these aggregators (Exh. BGC-1, at 9-10). The Company's capacity release proposal would require marketers or aggregators, once they have assembled sufficient load, i.e., 100 Mcf/day threshold, to take assignment of a predetermined pro rata portion of upstream pipeline and underground storage entitlements at the applicable FERC maximum tariffed rates (Exhs. BGC-1, at 10; BGC-73, § 11.1; BGC-74, § 11.1). The Company proposed calculating the pro rata share based on a given customer's average daily use during the 1995/96 peak month (Exhs. BGC-1, at 12; BGC-73, § 11.1; BGC-74, § 11.1).[91]

Further, Boston Gas proposed to assign customers to either the Tennessee or Algonquin pipelines, depending upon the customer's geographic location (Tr. 5, at 114-115). According to the Company, each eligible customer would receive a pro rata "slice" of all the contracts that "feed" either the Tennessee or Algonquin pipelines from the wellhead to the city gate (Tr. 5, at 114-115). The Company also proposed to release this capacity for the

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[90] Eligible customers include all firm sales customers of record as of October 1, 1996, as well as all firm transportation customers of record as of October 1, 1996 who were former firm sales customers and who have elected to accept their pro rata share of capacity; and all bundled, firm 365-day non-core customers of record on October 1, 1996 who have elected to accept their pro rata share of capacity (Exh. BGC-72; Tr. 14, at 193-194).

[91] Specifically, Boston Gas proposed to assign capacity by multiplying the customer's average daily use in the peak month, 1995/96, by the ratio of peak month daily firm sendout met with pipeline capacity (or firm storage withdrawal) to peak month total average daily firm sendout (Exh. BGC-1, at 12).

respective term of the contracts, and stated that it would retain the rights of recall to ensure that capacity generally runs with the meter as customers move within and beyond the system (Exh. BGC-1, at 10-11; Tr. 5, at 112-113). The Company would use its recall rights from time to time to correct mismatches between customer load assigned capacity beyond a 100 Mcf/day tolerance (Exh. BGC-1, at 11). The Company proposed to use this recall mechanism through the year 2000, at which point of unexpired capacity would be released without rights of recall (id.).

The Company would allocate most of its underground storage entitlements on the same basis as pipeline capacity, but would continue to retain some of these entitlements to meet system balancing needs (Exh. BGC-1, at 12-13).

2. DOER'S Proposal

DOER has proposed a voluntary capacity assignment with a mandatory availability plan, which incorporates a three-step implementation process (Exh. DOER-71, at 15). According to DOER, Step One would allow all firm sales customers of record as of a specific date, and/or marketers acting on their behalf, to have the option of taking the desired type and level of their pro rata share of both upstream and downstream capacity, or some smaller increment at maximum rates as they migrate from sales to transportation service (id.; Exh. BGC-145). DOER explained that under its proposal, the pro rata share should "stay with the meter," and, therefore, be subject to the same recall rights proposed by Boston Gas (Exh. DOER-71, at 15). In Step Two, any remaining capacity would be made available to those customers on Boston Gas's system that are not eligible for the initial capacity selection, including current firm and interruptible transportation, interruptible sales, and non-core customers (id.). The capacity would be offered at FERC maximum tariffed rates, would be

subject to the same recall rights applied in Step One, and customers could choose the amount of capacity they wish to take (id.).

DOER explained that in the event that additional capacity remains after Step Two, Boston Gas would make this capacity available in Step Three through an auction process to interested customers or marketers as a means of mitigating potential stranded costs (id.; Tr. 19, at 46). DOER further proposed that Boston Gas retain discretion to determine which mechanisms to use to make this capacity available and the proper timing for their employment (Tr. 19, at 46). DOER contemplates that recall rights could be attached during a transition period to the extent necessary to maintain reliability (Exh. DOER-71, at 21; Tr. 19, at 178).

To mitigate stranded costs, DOER proposed requiring Boston Gas to credit revenues from capacity release and off-system sales made using its merchant portfolio, revenues from IT, and revenues from the release of downstream assets at market-based rates (Exh. DOER-71, at 18). According to DOER's proposal, Boston Gas would be given a reasonable opportunity to recover these and any remaining stranded costs not fully offset by the revenue credits (id.).

3. Positions of the Parties

a. The Attorney General

The Attorney General states that he sees merit in both capacity assignment proposals (Attorney General Brief at 97). In the interim, however, the Attorney General recommends that, subject to certain modifications, the Department allow the Company to implement a mandatory plan on December 1, 1996, for customers prepared to move to transportation service (id.; Attorney General Reply Brief at 47-48).

The Attorney General argues that any LDC unbundling plan must contain a commitment from Boston Gas to automatically renew, on a year-to-year basis, those capacity contracts that are due to expire in 1996, and in the rate year, at least through the transition period (Attorney General Brief at 97). Regarding automatically renewing the Company's capacity contracts, the Attorney General asserts that customers's access to transportation service, including their ability to switch marketers, must be protected until parties have the opportunity to consider the most efficient and effective disposition of these resources (id.).[92]

b. DOER

DOER argues that Boston Gas's proposed mandatory capacity assignment plan is not true unbundling because it fails to maximize choice and lower prices, i.e., marketers must pay for capacity and supply resources whether or not they intend to use them, resulting in the imposition of an "exit fee" (Exh. DOER-71, at 9-10; DOER Brief at 66-70). DOER contends that the Company's mandatory assignment proposal fails to allocate capacity efficiently for three main reasons: (1) a customer's pro rata share of capacity does not likely represent the optimal mix of capacity to serve each customer, thus preventing customers from realizing the full cost benefits of moving to a third-party supplier, resulting in the underutilization of less expensive resources, and/or distorting the price signals to determine whether new capacity should be offered; (2) suppliers who already possess capacity that could be used to serve Boston Gas's customers are unlikely to be able to compete effectively, which may, in turn, represent a barrier to entry; and (3) it would be

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92 The Department addresses the Attorney General's concerns regarding the "performance bonding" issue in Section XII.C.1, and the "no penalty on interim sales service" issue in Section XII.C.2.

difficult for marketers to re-market small pieces of unwanted upstream capacity if other marketers are trying to do the same (Exh. DOER-71, at 10-11; DOER Brief at 70-75).

Moreover, DOER asserts that mandatory assignment will lead to unfair and discriminatory results, because this plan (1) imposes different costs and benefits on its customers in the initial assignment, depending on whether a customer is an "Algonquin" or "Tennessee" customer, (2) conceals the existence of stranded costs, because any that exist are transferred directly to customers or their marketers, and (3) does not fairly allocate stranded costs among participants, because customers for which the pro rata mix is optimal would essentially pay no stranded costs (Exh. DOER-71, at 11; DOER Brief at 76-79).

In support of its own proposal, DOER argues that its voluntary approach would maximize customer choice by allowing (1) migrating firm sales customers and/or the marketers serving these customers to determine the types of resources desired from the Company's portfolio, the necessary volumes, and the opportunity to use alternative resources that may provide greater cost savings, (2) other non-firm sales customers who are ineligible for initial capacity selection to obtain capacity (Exh. DOER-71, at 16; DOER Brief at 67-68). DOER also contended that its plan would result in a more efficient allocation of resources compared with mandatory assignment, because (1) marketers may utilize the lowest cost mix of capacity ("productive efficiency")[93] to serve customers that value the product or

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[93] DOER states that productive efficiency is met when market conditions are such that the least expensive resource is optimized, and the clearest price signal is sent as to whether new capacity should be offered (DOER Brief at 71). DOER also states that a result of failing to meeting productive efficiency is that the migration of customers from firm sales to firm transportation would be slower (id. at 72).

service the most ("allocative efficiency"),[94] and (2) Boston Gas is in a better position to capture economies of scale in the transfer of unwanted capacity (Exh. DOER-71, at 16-17; DOER Brief at 70-73, 75). In addition, DOER states that its proposal would result in a more fair allocation of resources because (1) no customer would be forced to accept an unequal share of the burdens of transition, and (2) stranded costs, which result under either unbundling plan and are a system-wide problem that should be resolved through a system-wide solution, would be identified, quantified, mitigated, and apportioned through a non-bypassable surcharge (Exh. DOER-71, at 17-18; DOER Brief at 76-79). According to DOER, adoption of its proposal would not result in marketers trying to "game" the process by waiting until Step Three to acquire capacity not likely at below FERC maximum rates, because if capacity is truly needed by marketers to serve this market it will be acquired in Step One (DOER Brief at 18).

DOER challenges the Company's assertion that mandatory assignment can ensure greater reliability of supply than the voluntary plan (id. at 79). Specifically, DOER argues that the record shows that if recall rights are applied to all three steps of the voluntary proposal, then a voluntary plan is at least as effective as Boston Gas's proposal from a reliability perspective (id. at 80, citing Exh. DOER-71, at 20; Tr. 22, at 43, 46-47; 53; DOER Reply Brief at 16). DOER argues that the Company's reliability argument is suspect,

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94 DOER states that allocative efficiency is met when market conditions are such that goods are allocated to those who value them most (DOER Brief at 72). DOER recognizes, however, that the allocative efficiency promoted by the voluntary plan is not absolute, because (1) recall rights would be maintained to make sure that capacity can be used to serve Boston Gas's customers (i.e., maintain reliability), and (2) the FERC maximum rate cap on capacity release distorts the market from determining whether capacity is indeed assigned to those who value it most (id. at 73). Despite these limitations, DOER argues that voluntary assignment promotes allocative efficiency more effectively than Boston Gas's plan (id.).

because it appears Boston Gas, itself, intends to allow its upstream pipeline and storage contracts to expire during the transition period (DOER Brief at 81, citing Tr. 1, at 200-201; Tr. 5, at 142-145). Accordingly, DOER states that Boston Gas should evergreen or renew existing capacity contracts during the transition period (DOER Brief at 81 n.58; DOER Reply Brief at 17 n.13). DOER recommends that the Department defer considering the exact legal mechanism and duration of recall rights for Phase II, because if voluntary assignment is adopted on an interim basis, there will be time in Phase II to resolve the issue of recall rights before any auction occurs (DOER Reply Brief at 15).

DOER disputes the Company's assertion that a voluntary plan creates a disconnect between stranded costs and stranded benefits (id. at 18). With respect to "stranded benefits," DOER states that there are potential stranded benefits under either proposal, because there is currently a cap on the rate that Boston Gas can transfer to third parties; however, DOER observes that those parties can evade the cap and resell the capacity at a mark-up through "gray" market transactions (id.).[95] With respect to "stranded costs," DOER states that while customers will absorb stranded costs under both proposals, under a mandatory plan stranded costs will be hidden and borne by particular customers whose load profiles do not match the shares of capacity assigned to them (id.).

DOER also challenges Boston Gas's position that under a voluntary assignment plan, a customer who migrates and takes the entire pro rata share will be unfairly burdened by also having to pay a stranded cost surcharge (id. at 19). DOER contends that when customers take their full pro rata share, that is simply a reflection of the fact that for these customers,

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95 For the purposes of this Order, a gray market is a market in which a seller, by offering a bundled service, can circumvent the maximum tariffed rates on pipeline capacity established by FERC.

the slice that Boston Gas has assigned is optimal (id.). DOER argues that these customers's "good fortune," however, is no reason to absolve them from responsibility for paying for the slices that are not optimal, and that stranded costs, if any, are a system-wide problem (id. at 19-20).

Addressing Boston Gas's assertion that the voluntary capacity plan forces the Company to mitigate costs of assets that it no longer controls, DOER asserts that its plan actually calls upon Boston Gas to retain ownership of the capacity until it is sold (id. at 20-21). This would mitigate potential stranded costs by attempting to transfer capacity to those who value it in a series of phased and orderly stages (id.).

In response to the Company's contention that the "snapshot" nature of an auction mechanism would fail to capture the true value of capacity, DOER states that its plan calls for Boston Gas to time the auction (or make other sales of capacity) in a manner that is best slated to capture the capacity's highest value (id. at 21). DOER recognizes that it is always possible that an auction or a sale at another time could generate a different price, but reasons that the applicable standard here is not perfection judged in hindsight (id.). DOER states that if Boston Gas shows reasonable judgement in disposing of the unwanted capacity in Step Three, then the Company should be entitled to recover the difference between the market price and the contract rate after any offsets from other revenue-producing investments (id.).

DOER concludes that Boston Gas has not provided any persuasive argument that the advantages of voluntary assignment are outweighed by the risks (id. at 22). Rather, DOER contends that the only real problem Boston Gas has with voluntary assignment is that it would share some of the responsibility for addressing stranded costs (id.).

In response to the Company's claim that a voluntary plan would impose a significant administrative burden on all parties, DOER contends that the record in this case reveals no basis for this conclusion (DOER Brief at 84). DOER also argues that the adjudication of stranded costs need not be difficult or expensive (id. at 85). Lastly, DOER states that an analysis of the administrative expense of adjudicating stranded costs would be incomplete unless it is compared to the costs that customers and marketers would bear under Boston Gas's proposal when forced to take unwanted capacity and market it elsewhere (id. at 85-86).

DOER disagrees with the Company's claim that its three-step plan is too "amorphous" to be approved (DOER Reply Brief at 15). DOER asserts that the voluntary plan is sufficiently well developed to determine which capacity assignment proposal is superior (id. at 15). Further, DOER states that to the extent that certain operational details are lacking in its plan (e.g., the timing of Steps One, Two, and Three), there is still time for Boston Gas and other parties to finalize such details (id.).

DOER states that it does not share the view that the Department must defer resolving the capacity release issue to Phase II of this proceeding (id. at 10-11). However, DOER recommends that, should the Department determine otherwise, Boston Gas should be ordered to implement a voluntary capacity release program on an interim basis (id. at 11). DOER asserts that voluntary capacity should be required on an interim basis because voluntary capacity: (1) is supported by those parties most affected by it in the short run; (2) it would be more effective in stimulating a competitive market; (3) would provide the opportunity to ascertain whether problems really do exist with this type of regime; and (4) would provide the opportunity to ascertain whether there are likely to be any stranded costs on a permanent basis, and if so, what the magnitude of those costs is likely to be (id. at 12-13).

c. Bay State

Bay State indicates that both the mandatory capacity or voluntary capacity assignment proposals put forth by Boston Gas and DOER may work (Bay State Brief at 7). However, Bay State indicates that, given the practical complications associated with mandatory assignment (e.g., the potential of assigning small quantities of capacity), the voluntary approach may be more efficient, and, therefore, result in lower overall costs (id.).

d. Berkshire

Berkshire states that, given a number of LDC-specific circumstances which need to be considered, Berkshire recommends that the Department not issue any binding capacity assignment-related decisions in Phase I of this proceeding which may have significant impacts on customers and LDCs throughout the Commonwealth (Berkshire Reply Brief at 1-3). Accordingly, Berkshire proposes that capacity assignment be allowed only on an interim basis, subject to full recall, so that structural issues can be fully considered and decided first (id.)

e. ComGas

ComGas strongly recommends that any capacity release mechanism approved in Phase I be interim pending the outcome of Phase II (ComGas Brief at 15). ComGas suggests that the allocated, pro rata shares of capacity be released on a year-to-year basis and be subject to recall as proposed by Boston Gas (id. at 16). ComGas recommends an interim mandatory capacity release mechanism at FERC maximum tariffed rates (id. at 17).

f. Essex

Essex contends that the Department should permit Boston Gas to implement only a temporary capacity release program, whereby Boston Gas would continue to manage its

upstream pipeline and storage portfolio (Essex Brief at 4-5; Essex Reply Brief at 2). Essex maintains that the Company's management of these assets should include, when appropriate, the extension of existing contracts scheduled to expire before the end of the transition period established by the Department in Phase II (Essex Brief at 6). Essex also proposes that a Phase I capacity release mechanism should be temporary, reversible, recallable, and should not transfer rights of first refusal, so that capacity would not be permanently lost for Massachusetts customers and diverted to other markets (id.; Essex Reply Brief at 2).

g. Algonquin

Algonquin states that while there are certain deficiencies with Boston Gas's proposal, the Company's plan is significantly better than DOER's voluntary capacity assignment proposal regarding maintaining control over access to upstream pipeline and storage capacity (Algonquin Brief at 4 n.3).

However, Algonquin raises several concerns over reliability issues. First, Algonquin states that unless Boston Gas takes a proactive stance toward managing its upstream capacity contracts during its restructuring efforts, system reliability could be at risk,[96] and new suppliers could be subject to longer term obligations under existing upstream transportation agreements than are now in place (id. at 6). Algonquin points out that more that 62 percent of Boston Gas's existing pipeline capacity with Algonquin is currently in evergreen status,

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[96] Algonquin contends that Boston Gas's proposed capacity assignment program in its current form, which would allow these contracts and resulting recall rights to terminate, does not ensure reliable transportation service, and would have the effect of approving Boston Gas's proposal to exit the merchant function before consideration of this proposal in Phase II (Algonquin Brief at 11-12, 23, 26).

which is equivalent to approximately 38 percent of Boston Gas's total daily deliverability (id. at 15; Algonquin Reply Brief at 2).

To address these concerns, Algonquin advocates that Boston Gas extend through at least the year 2002 all upstream capacity and storage contracts that are in evergreen status or terminable before such date (i.e., after the date the Company's proposes to exit the merchant function) (Algonquin Brief at 8, 27, 30). Algonquin states that the extension of these contracts, for a specific term, e.g., the year 2002, would secure reliability throughout the period of extension, thereby removing the existing risk associated with the evergreen provisions (Algonquin Reply Brief at 2).

Algonquin argues that this structure of primary delivery points and primary receipt points in Boston Gas's design of its capacity release proposal, if left uncorrected, would result in serious reliability issues associated with a transportation customer's ability to receive gas supplies (Algonquin Brief at 36). Algonquin also argues that this structural defect is further exacerbated by significant price disparities that currently exist among Boston Gas's eleven contracts with Algonquin (id. at 36-38).

h. Tennessee

Tennessee states that it supports the LDCs's continued involvement with the management of upstream storage capacity, and states that the unbundling of this capacity is much more complex than pipeline transportation unbundling (Tennessee Brief at 2-3). Tennessee is concerned that proper upstream storage management, which is essential to Tennessee's ability to maintain its system's integrity, may be negatively affected if each contract is subdivided and placed in the hands of inexperienced shippers (id. at 3).

Tennessee advocates that each LDC coordinate with its interconnecting pipeline(s) relating to operational and tariff issues in order to maintain a smooth interface between the systems to ensure end users are provided the most flexible, reliable, and safe services (id. at 4). Tennessee also recommends that Boston Gas remain in a contractual relationship with Tennessee at the city gate (i.e., maintain the Conjunctive Operational Balancing Agreements ("OBAs"), to assure control and an efficient method of balancing the flowing volumes) (id. at 5). Further, Tennessee states that it is critical that city gate receipt point and upstream capacity designations conform with the upstream pipeline's tariff (id. at 6). Specifically, Tennessee argues that receipt point designations at the city gate must precisely match the transferred upstream capacity (id. at 6-7).

i. AllEnergy

AllEnergy states that it supports the unbundling of gas supply service from transportation service in order to bring the benefits of competition to consumers (AllEnergy Brief at 1). AllEnergy adds that facilitating the development of efficient competition in the gas supply market should be the goal of the Department in this proceeding (id.).

j. Enron

Enron opposes mandatory capacity assignment and is in favor of DOER's voluntary plan (Exh. ECT-1, at 4; Enron Brief at 3; Enron Reply Brief at 3). Specifically, Enron advocates that marketers should have the option to select their own delivery points into Boston Gas's system (Exh. ECT-1, at 4; Enron Brief at 3; Enron Reply Brief at 3). Enron argues that consumers will benefit from voluntary capacity assignment because, in the long run, upstream capacity will cost less than if it is assigned on a mandatory basis at maximum rates (Enron Brief at 4). In addition, Enron asserts that Boston Gas will maintain an unfair

advantage in terms of price and convenience in serving sales customers prior to its possible exit from the merchant function (id.).

k. TMG

TMG states that Boston Gas's proposal recognizes two critical initial requirements for a successful unbundling program: (1) customers must have access to reliable, firm upstream pipeline and storage capacity; and (2) customers must have access to upstream capacity sufficient to transport their peak day requirements on a firm basis (TMG Brief at 4). TMG also states that, in order to give customers real choices and opportunities, customers must have the option to take some or all of their pro rata share of upstream capacity (id. at 5). TMG argues that requiring marketers to take capacity they do not want or need would create a significant risk that the entire restructuring program will prove uneconomic and unworkable, because it would severely constrain the customer's flexibility to secure the appropriate mix of supply, long- and short-haul pipeline capacity, and upstream storage, from several competing marketers (id. at 1-2, 5; TMG Reply Brief at 2-3). TMG opposes the mandatory nature of Boston Gas's upstream capacity assignment plan, contending that customer choice of what assets to purchase is the key component of an unbundling program (TMG Brief at 4, 6). TMG advocates that the Department require Boston Gas to replace its proposal with a "mandatory-availability, optional-take" program, as proposed by the DOER, including the three-step process (id. at 10, 13-14; TMG Reply Brief at 3).

TMG contends that much of the reasoning behind Boston Gas's mandatory approach to capacity allocation is based on the elimination of its risk and exposure to perceived stranded capacity costs (TMG Brief at 8). TMG further asserts that the Company has apparently failed to recognize that there are many other means to avoid stranding costs,

including implementing open market capacity bidding programs, load growth, relinquishing capacity, and allowing existing sales customers to give notice of their intention to convert to transportation in advance of an election not to take released capacity (id. at 8-10). TMG recommends that a proceeding be convened to address stranded capacity costs only if and when they have accrued (id. at 9).

l. Texas-Ohio

Texas-Ohio submitted prefiled testimony in support of Boston Gas's unbundling proposal, stating that the mandatory capacity assignment plan would lead to a fully competitive market in an expedient, smooth, and fair manner (Exh. TOG-1, at 2). In contrast, Texas-Ohio argued that DOER's optional capacity assignment approach would needlessly delay competition and require complex administrative and regulatory procedures that will not produce savings for customers, but will create unnecessary confusion and disruption, and give an advantage to large customers at the expense of smaller customers (id.). Texas-Ohio stated that its main concern with DOER's voluntary plan is the disposition of upstream capacity not taken by marketers (i.e., stranded costs) (id. at 3-8). Texas-Ohio concluded that, given the limited pipeline capacity serving Massachusetts, mandatory capacity assignment would ensure customers have access, and would ensure that their access is on the same basis and price as other marketers (id. at 9).

m. AIM

AIM states that even though the voluntary capacity assignment proposal may be more efficient, cost effective, and maximize customer choice, whichever capacity assignment regime the Department approves, such a system must include customer education, customer protection, and the ability to reduce costs over the short- and long-term (AIM Brief at 17).

AIM recommends that Boston Gas be directed by the Department to retain its pipeline capacity contracts during the transition period to ensure that this capacity is not taken out of state (id. at 20).

n. Low-Income Intervenors

The Low-Income Intervenors state that a number of factors suggests that mandatory allocation of capacity is the best regulatory policy, for the following reasons: (1) mandatory assignment assures that all buyers who leave the bundled service of Boston Gas will take with them a share of their capacity which the Company acquired to serve them; (2) it remains unclear whether the benefits of voluntary assignment would accrue to captive, residential customers; and (3) mandatory assignment would clarify the switch between the current bundled regime and an unbundled system (Low-Income Intervenors Brief at 8-9).

o. TEC

TEC states that it is in favor of making upstream interstate pipeline and storage capacity contracts available to Boston Gas customers, and concurs with the need for voluntary capacity assignment with mandatory availability priced on a cost-of-service basis (TEC Brief at 15-16).

With respect to reliability, TEC recommends that the Company retain recall rights of all capacity necessary to maintain reliability, including capacity in evergreen status, for a term extending through the year 2000, or until the Department makes a finding that capacity is no longer necessary to maintain reliability or deliverability or that workable competition exists in the Company's service territory (TEC Reply Brief at 3-5).

p. The Company

Boston Gas asserts that its unbundling plan seeks to create a transitional market structure that attracts many entrants, introduces competition to capacity management, and promotes customer choice, while recognizing the operating constraints in New England and the market imperfections created by capacity price regulation (Company Brief at 3-4, 8, 22). The Company claims that in recognition of the potential problems attributable to transitioning from a regulated, sole-merchant gas market to a competitive one, it has developed a program that will allow a competitive market with many buyers and sellers to flourish, and afford basic protections to customers (id. at 8). Specifically, the Company argues that the playing field would be leveled by allocating pro rata shares of the Company's capacity portfolio to marketers chosen by customers at maximum tariffed rates (id. at 4). The Company anticipates marketers would compete with one another to generate the highest value from the allocated capacity, and pass these savings on to customers in the form of lower prices (id.). Boston Gas contends that while it shares many of DOER's objectives, it differs with DOER as to the best way to achieve these objectives (id. at 8).

The Company argues that DOER neither clearly nor correctly contemplates how recall provisions should be handled for capacity going to auction in Step Three (id. at 17-18). The Company argues that its recall provisions simply cannot be attached to capacity auctioned in Step Three, i.e., capacity made available in Step Three cannot be restricted to marketers serving Boston Gas customers (id. at 18, 23). The Company states that its plan taken as a whole strikes an appropriate balance between attracting responsible competitors and preserving supply reliability (Company Reply Brief at 18).

The Company contends that while DOER's voluntary capacity assignment proposal may appear to offer customers more choice than its own mandatory plan, the Company's plan is superior to DOER's in terms of protecting customer choices through the transition (Company Brief at 19). Specifically, Boston Gas contends that customers may be worse off under DOER's plan because customers bills would increase if they bear higher costs for resources to replace capacity migrating elsewhere (id. at 20, 23-24).[97] Further, Boston Gas argues that if the supplier fails, the Company can only recall a fraction of its customers's peak needs under DOER's proposal (id. at 20). Boston Gas states that it agrees with the recommendation offered by Algonquin that the Company extend its firm transportation agreements presently in evergreen status to assure the availability of that capacity through the transition period (Company Reply Brief at 15).

In regard to stranded costs, the Company argues that its mandatory assignment plan positions customers to receive value earned by their suppliers from capacity sold on the gray market (Company Brief at 22). Boston Gas explains that the FERC-imposed maximum rate cap on released pipeline capacity skews any market valuation of capacity at auction, because released capacity can be sold at less, but not more, than its cost, regardless of its market value (id. at 21). Further, the Company states that marketers may avoid the rate cap through sale for resale, by bundling supply and capacity in the gray market (id. at 22). The Company contends that if capacity were made available in Step Three for DOER's auction process, this capacity can only be discounted, and customers would face only downside risk from a capacity auction (id. at 21-22).

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97 The Company emphasizes that because the availability for pipeline capacity in New England is in short supply, the ability of capacity to migrate to other markets places deliverability to customers at risk and threatens their choices (Company Brief at 21).

The Company claims that its mandatory assignment proposal minimizes stranded costs at the outset by mixing in each supplier's allocated share of capacity of different values, thus spreading costs across the system equitably (id. at 26). Boston Gas acknowledges that its portfolio contains some capacity that will be more valuable than its cost and some that will be valued below cost (id.). The Company argues, however, that a program allowing suppliers to selectively choose contracts and pay market rates, as DOER proposes, will not change its contractual commitments (id.). Further, under its proposed plan, Boston Gas expects suppliers themselves to net stranded benefits, which accrue where suppliers remarket capacity at prices exceeding FERC maximum rates by bundling it with supply, against stranded costs (id. at 27). The Company argues that because it would assign all capacity at cost, and pass all stranded costs and benefits to marketers at once, the Company's plan positions customers to receive the maximum value from allocated capacity, which is the single highest cost component for customers (id. at 24-25, 27).

In contrast, the Company asserts that DOER's voluntary assignment plan requires that the stranded cost issue be addressed by everyone but the competitive market (id. at 25). The Company further asserts that DOER's plan establishes a disconnect between stranded costs and stranded benefits, leaving the former to customers and the latter to unregulated marketers, thus defeating the purpose of restructuring completely (id. at 27). The Company also contends that DOER's plan requires that (1) the Company mitigate the costs of assets it no longer controls, (2) the Department adjudicate stranded cost identification, mitigation and recovery, and (3) customers pay for such costs (id. at 25-26). The Company cites several reasons why it sees the handling of stranded costs under DOER's plan as a regulatory and equity problem, which will increase costs for consumers, including (1) the price volatility of

capacity during the year, (2) the price uncertainty of stranded costs over time, (3) the imposition of stranded costs on customers who have already taken their full pro rata share of capacity, and (4) the increased administrative overhead (id. at 28-32).

The Company also takes issue with DOER's assertion that stranded benefits would exist under either the mandatory or the voluntary plan because in either case marketers will be able to evade the maximum rate cap in gray market transactions (Company Reply Brief at 20). The Company asserts that under the mandatory plan, marketers will have economic incentives to manage capacity to its fullest (id. at 21). The Company concludes that until there is a vigorously competitive market, there will be little incentive for marketers to net benefits obtained from sales of capacity in the gray market against stranded costs paid by all customers through a distribution charge (id.).

The Company recommends that in approving a capacity assignment program in Phase I, the Department should be mindful of two equity issues: (1) no customer should be disadvantaged as a result of being an early or late mover in migrating from sales to transportation; and (2) the Company should not be disadvantaged for its unbundling initiatives (id. at 8). The Company also suggests that the Department, in considering which capacity assignment program would serve best in the interim period, review FERC Order 636-A and other unbundling programs, including those of California and New York, where there is sufficient data to judge their success (id. at 8-9).

The Company identifies several problems with DOER's recommendation to approve, if necessary, an interim voluntary capacity assignment plan (id. at 10). In addition, the Company takes issue with DOER's position with respect to the specific recall rights that would be attached in the Step Three auction (id.). Further, the Company claims that it is

unable to discern how, if no Step Three occurs before Phase II is resolved, there would be any information available regarding stranded costs (id. at 11).

4. Analysis and Findings

The Department has recognized that based on the interrelationship of the Company's proposal to exit the merchant function with the proposed capacity assignment program, the Department could reach an interim decision in Phase I, and render a final determination in Phase II. Hearing Officers's Ruling on Scope at 4. After review of the evidence in this case and in consideration of the arguments of the parties, the Department finds that capacity assignment requires an interim decision.

In D.P.U. 93-60, at 281, the Department approved Boston Gas's proposal to unbundle its firm sales rates and recover gas costs through the CGAC. The Department recognized that this practice was an important step in the movement toward a competitive gas supply market. Id.; see also D.P.U. 95-104; Commonwealth Gas Company, D.P.U. 95-102 (1995); and Colonial Gas Company, D.P.U. 93-104-C (1995). In Electric Industry Restructuring, D.P.U. 95-30, the Department announced restructuring principles that would support the development of and transition to a competitive electric generation market.

The Department's existing gas unbundling precedent and electric restructuring principles provide appropriate guidelines to determine which capacity assignment plan is most reasonable during the interim period. Accordingly, to assess the reasonableness of the upstream pipeline and storage capacity assignment plans that are before us, the Department must determine that such an interim plan: (1) facilitates the Company's movement toward a more competitive natural gas supply market; (2) maintains adequate and reliable service;

(3) enables the Company to honor existing commitments; and (4) is expeditious, orderly, and minimizes customer confusion.[98]

The Department notes that it is not our intent to use the interim period as a test for determining whether one capacity assignment proposal is better than the other. Rather, it is our intent to approve a reasonable interim plan that is in the best short-term interest of the Company's customers, and which facilitates the movement toward a more competitive market, until a final decision is issued in Phase II. Therefore, it would be inappropriate to approve an interim voluntary capacity assignment plan only for the purpose of ascertaining whether this approach poses actual administrative and regulatory problems, or whether there are likely to be any stranded costs on a permanent basis. Nor will the Department approve a plan simply because it is supported by those parties who claim to be "most affected" in this case.

DOER acknowledges that its proposed voluntary assignment plan leaves certain issues unresolved and recommends that they be addressed during Phase II of this proceeding. In particular, DOER suggests that the exact legal mechanism and duration of recall rights under Step Three of the voluntary plan be deferred for discussion until Phase II because, according to DOER, there will be time to resolve this issue before an auction occurs under Step Three. The Department notes that DOER's voluntary plan might have been appropriate for the interim period if the questions regarding the Step Three recall rights were resolved now. However, the Department notes that the record is not clear whether the Company would

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98 The Department notes that we apply the same standards in determining the reasonableness of the capacity assignment plans for the Company's Canadian supply contracts, downstream capacity, monitoring and evaluation efforts, and implementation schedule in Section X.E, below.

reach Step Three of the voluntary plan which requires an auction, before a Phase II decision is issued.[99] Accordingly, because of the uncertainty surrounding the timing of both Step Three, and a final decision in Phase II, we cannot at this time, accept DOER's proposed plan. In contrast, and for the interim, the uncertainties described above do not exist under the Company's mandatory plan. The Company's plan as proposed is easier to administer and in view of the anticipated need for customer education regarding capacity assignment, it is more likely to minimize customer confusion during the interim period.

The Department shares the concern of the parties that the reliability of Boston Gas's system must not be compromised during the transition toward a competitive gas supply market. The record shows that Boston Gas agrees with certain intervenors's recommendation to extend all upstream capacity and storage contracts that are in evergreen status or terminable. The Department finds that it is reasonable to extend all these contracts in order to ensure adequate and reliable service before a final decision is rendered in Phase II. Accordingly, the Department directs Boston Gas to extend all of its upstream pipeline and storage capacity contracts necessary to maintain reliability through the interim period. The Department will address in Phase II whether these contracts should be extended beyond the interim period.[100]

Regarding Tennessee's assertion that making upstream storage available to inexperienced marketers may negatively impact the pipeline's ability to manage these

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99 Issues related to Step Three of DOER's voluntary plan, including recall rights, reliability, and stranded costs, must be examined more closely in Phase II before determining the reasonableness of such plan.

100 The Department notes that this directive in no way diminishes the Company's responsibility to actively manage its capacity assets to maximize efficiency and minimize gas-related costs to end-users during the interim period.

resources, the Department takes this concern seriously, and strongly recommends that Boston Gas do so as well. The record is incomplete on this matter and, accordingly, the Department defers ruling on Tennessee's recommendation for Boston Gas to remain in a contractual relationship with Tennessee at the city gate, until this issue can be further examined in Phase II.

Regarding the issue of mismatches between primary delivery and primary receipt points raised by Algonquin, the record evidence indicates that Boston Gas has yet to resolve the mismatch problem (RR-DOER-15; RR-DOER-15 (Supp.)). The Department finds that this issue must be addressed to ensure a reliable interim plan. Accordingly, the Department directs Boston Gas to work with the necessary parties to address potential upstream capacity-related and/or deliverability problems attributable to local unbundling efforts, and to file a report on the status of these discussions in its Phase II prefiled testimony.

B. Canadian Supply Contracts

1. The Company's Proposal

The Company proposed to assign a pro rata share of its existing Canadian supply contracts to migrating customers or marketers serving these customers (Exh. BGC-72, at 2).[101] The Canadian supply is purchased on a bundled basis at the Canadian border, and transported in various quantities on the Iroquois, Tennessee, and Algonquin systems into Boston (Tr. 10, at 74; Tr. 20, at 68). The Company explained that these supply contracts make up

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[101] Boston Gas's portfolio of resources utilized to serve its firm customers includes long term supply contracts with Alberta Northeast, Ltd., Boundary Gas, Inc., and Imperial Oil Resources (collectively, the "Canadian contracts") (Company Brief at 32). These contracts expire in 2006, 2003, and 2007, respectively (Exh. DOER-1; Tr. 20, at 58).

approximately 12 percent of the daily delivered pipeline supply resources and do not have load loss provisions (Exh. BGC-200; Tr. 20, at 61; Tr. 21, at 36).

Boston Gas stated that the method for assigning these contracts would be identical to the method for the Company's upstream pipeline and storage capacity contracts (Exhs. BGC-73 § 11.1; BGC-74, § 11.1).

2. Positions of the Parties

a. DOER

DOER argues that Boston Gas's proposal to mandatorily assign a share of its Canadian supply contracts contravenes the whole purpose of natural gas restructuring, which is to functionally separate the competitive function of supply from the monopoly function of distribution (DOER Brief at 70). DOER states that this would also undermine the benefit that is supposed to accrue from unbundling -- allowing customers to make arrangements with their own suppliers (id.). DOER contends that, given that the commodity market is competitive, there is no basis for requiring customers to take a share of Boston Gas's Canadian supply contracts (id.). DOER states that although it opposes the Company's mandatory capacity assignment plan in its entirety, should the Department approve the Company's proposal, it must eliminate this mandatory assignment of supply (id. at 70 n.54).

b. Imperial

Imperial states that, regardless of the outcome of the overall pipeline capacity issue, Boston Gas must honor its obligations under the Imperial contract or assign the contract to entities acceptable to Imperial (Imperial Brief at 1, 9). Imperial argues that this result is required since (1) the transportation contracts held by Boston Gas are a necessary component of the overall gas supply arrangement, required to perform obligations under that contract,

(2) assignment of purchase obligations under the Boston Gas/Imperial contract cannot take place absent Imperial's written consent, (3) Imperial will not consent to assignment of the contract as part of either capacity allocation method presented in this case, and (4) the proposed treatment of the Imperial contract represents an administrative challenge for Imperial (id. at 1-2, 7-8). In addition, Imperial indicates that it is prepared to (1) pursue a negotiated, commercial resolution of all issues associated with the Boston Gas/Imperial contract as the best outcome in the event Boston Gas is authorized to exit the merchant function; and (2) entertain proposals from Boston Gas for assignment of the contract to an acceptable party (id. at 2 n.2).

c. TransCanada

TransCanada states that the ANE/Boston Gas agreement expressly provides that any assignment by Boston Gas of either the ANE/Boston Gas Agreement or any of Boston Gas's rights under the agreement to an unrelated third party that is not a U.S. Repurchaser requires, inter alia, the consent of TransCanada, which shall not be unreasonably withheld (TransCanada Brief at 7). TransCanada further states that upon any assignment, the assignee must acknowledge and accept in writing all obligations accruing under this agreement (id.). TransCanada concludes that any assignment requiring its consent, but made by Boston Gas without such consent, may be treated as a breach of the agreement (id.).

TransCanada asserts that it will not accept any arrangement that will potentially diminish its contractual rights (id. at 8-9). TransCanada insists that Boston Gas remain financially committed to full performance of the TCPL/ANE Agreement and the ANE/Boston Gas Agreement throughout their terms (id. at 9). TransCanada also asserts that it will continue to seek ease of administration of its contract and enforcement of its rights under the

contract (id.). In addition, TransCanada states that it prefers to hold any discussions about the effect of Boston Gas's proposals in this proceeding on their contractual relationship directly with Boston Gas (id. at 8).

d. Enron

Enron opposes Boston Gas's proposed mandatory assignment of Canadian supply contracts and related capacity (Enron Brief at 3, 6). Enron argues that because Boston Gas will continue to have a substantial merchant function it is premature at best and inappropriate at worst to require converting sales customers to purchase a share of Boston Gas's unbundled Canadian supply and the capacity between the border and Boston Gas's city gate (id. at 3-4, 7). Further, Enron maintains that one of the central precepts of unbundled service is that, all other things being equal, the customer should save money as a result of the unbundling of services and the competition for gas purchases at the wellhead (id. at 6). If competing suppliers must assume one of Boston Gas's supply purchase obligations, the impact of the suppliers' ability to acquire gas at a price lower than those offered by Boston Gas will be lessened (id.).

e. TMG

TMG states that, for the same reasons that it opposes mandatory capacity assignment, mandatory assignment of a pro rata share of Boston Gas's long-term Canadian supply contracts would defeat customer choice, is bad public policy, and should be rejected (TMG Brief at 10-13; TMG Reply Brief at 3).

f. TEC

TEC recommends that any proposal to allocate the Canadian supply contracts to migrating customers should be rejected, and Boston Gas should continue to manage these

contracts for the benefit of its existing gas supply customers (TEC Brief at 16). TEC asserts that, after reviewing the Canadian contracts, there does not appear to be any basis for assigning a portion of the contracts to customers, and to do so would be difficult, if not impossible, for customers to manage (id. at 16-17).

g. The Company

The Company argues that it would be inappropriate to retain these Canadian supply contracts for the sole purpose of serving its remaining sales customers through the transition period (Company Brief at 33).[102] According to the Company, not to include Canadian supply contracts in its mandatory capacity assignment program would serve only to benefit those customers choosing to migrate early while leaving remaining customers to shoulder the higher cost (id.). The Company further states that assigning domestic capacity to customers as they migrate to transportation without assigning them a corresponding share of the Canadian contracts would eliminate the Company's ability to receive the supply it is obligated to take, thus stranding these contracts at the border (id.). Under this scenario, the Company contemplates suppliers having the economic incentive to minimize the costs of these assets, which, Boston Gas argues, would be the most equitable way to assure that customers obtain full value for their investment (id. at 33-34).

Boston Gas asserts that Imperial's assertion that the Company's proposal would impose administrative burdens does not constitute a legal basis for Imperial to withhold consent to an assignment of the Company's contractual rights to a financially qualified supplier (id. at 34).

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102 Boston Gas explained that because FERC 636 does not apply to Canadian pipelines, these contracts continue to be purchased as supply bundled with capacity on TransCanada Pipeline (Company Brief at 33). Further, the Company stated that because they are as much capacity as supply, the Company proposes that the Canadian contracts be included in its capacity allocation program (id.).

Although the Company recognizes that Imperial must consent to any assignment, the Company asserts that such consent may not be unreasonably withheld (id.). The Company states that it intends to honor its contractual obligations and expects Imperial to do the same (id. at 35). The Company suggests that, if necessary, as an interim measure, it could effect the transfer of Canadian supply volumes to suppliers through a sale for resale at the Canadian border where the Company manages the daily activities associated with the contracts (id. at 34-35).

3. Analysis and Findings

The record shows that the Company's Canadian supply contracts represent twelve percent of Boston Gas's daily delivered pipeline supply resources. We note that only a fraction of this amount will go to serve migrating C&I customers during the interim period. Therefore, it is unlikely that their required purchase would present an insurmountable barrier for marketers seeking to conduct business in the Company's service territory pending a final resolution to this matter. In addition, the Department finds that, at least during the interim period, the Company's proposal is a reasonable step to ensure that all customers would continue to receive adequate and reliable service. The record also demonstrates the Company's agreement to transfer Canadian supply volumes to suppliers through a sale for resale arrangement. Accordingly, the Department allows the Company to mandatorily assign its Canadian supply contracts on a sale for resale basis at the Canadian border during the interim period.[103]

The Department concludes that many outstanding financial, legal, and jurisdictional questions remain regarding these Canadian supply contracts. Accordingly, the Department

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103 The Department notes that the acceptance of this arrangement in no way absolves the Company from taking all practicable measures to mitigate potential future stranded costs associated with these contracts. See D.P.U. 95-30, at 29.

strongly encourages Boston Gas to explore during the interim period alternative arrangements which are acceptable both to the Company and all other contractual parties, and to be prepared to address these questions during the Phase II proceedings.

C. Downstream Capacity

1. The Company's Proposal

Boston Gas proposed to continue to own and operate its LNG and propane production facilities, and use a significant portion of these facilities to maintain deliverability on the distribution system (Exh. BGC-1, at 14). The Company stated that it plans to lease to third parties the portion of its downstream assets it does not need to provide daily and monthly balancing, and to price this capacity at market based rates (id. at 14-15). The Company also stated that during the period of its withdrawal from the merchant function, it would flow back to firm sales customers 100 percent of the revenues generated from leasing these assets, and would retain such revenues after exiting the merchant function (id. at 15).

Boston Gas explained that to minimize gas costs during the transition period, the Company would market available capacity where it has the most value, whether by short-term releases, interruptible sales at the city gate, or opportunity sales for resale (id. at 16). Boston Gas also proposed to flow back 100 percent of the margins earned from these transactions as a credit to customers's gas costs, and will no longer make firm sales of gas at the city gate under authority granted by the Department in D.P.U. 92-259 (id.).

2. DOER's Proposal

DOER proposed that the Department order Boston Gas to offer its customers their pro rata shares of downstream assets at cost-based, regulated rates consistent with its offering customers their respective shares of upstream resources at maximum tariffed rates

(Exh. DOER-71, at 14). DOER stated that to the extent converting sales customers do not wish to utilize the Company's downstream capacity, Boston Gas should lease these resources at market-based, negotiated rates and credit these revenues to any stranded costs (id. at 15).

3. Positions of the Parties

a. DOER

DOER argues that the principal justification for assigning downstream assets is that the Company's customers are rightful owners of these assets (DOER Brief at 59). DOER argues that the assignment of downstream assets is critical, because Boston Gas's upstream capacity is not sufficient to meet the peak needs of its customers (id.). DOER notes that while Boston Gas expects little downstream capacity to be available during the transition period, this would change depending on the rate of migration of customers, the number of customers choosing optional transportation service, and the availability of balancing services provided by entities other than Boston Gas (id. at 60 n.51, citing RR-DPU-22). Accordingly, DOER recommends that the Department direct Boston Gas to update its analysis of available downstream capacity on an ongoing basis (id.).

b. TMG

TMG asserts that Boston Gas's proposed approach for its downstream assets defeats customer choice by failing to acknowledge that converting customers paid for those assets and are entitled to the optional use of those assets at cost-based rates (TMG Brief at 14). By allowing the Company to control these assets as proposed, TMG argues that Boston Gas's shareholders would receive a windfall at its customers's expense (id. at 15). In addition, TMG contends that the Company's proposal fails to provide access to its on-system assets, which are necessary for the customer to secure its own peaking and balancing services, and

may prevent the option of true self-balancing (id.). Therefore, TMG suggests that Boston Gas be required to provide these assets to converting customers, at the customer's option to take them, and at a cost-based price, with any remaining capacity being leased at negotiated rates (id.).

c. AIM

AIM recommends that the Company's downstream assets, including LNG, propane, and storage facilities, be assigned to customers in a similar manner as upstream assets; on a pro-rata basis at maximum rates (AIM Brief at 20). AIM argues that downstream assets were acquired for the benefit of customers who paid for them and therefore are entitled to their use and benefit (id. at 20-21). Further, AIM argues that revenues generated from downstream assets should flow back to customers after the transition so that customers receive the full value for these assets (id. at 21).

d. TEC

TEC favors making downstream storage capacity available to Boston Gas customers on a cost of service basis (Exh. TEC-13, at 4; TEC Brief at 15). TEC argues that the excess downstream storage capabilities should be made available to migrating customers on a cost-basis, because (1) all customers have paid for these assets, and (2) this downstream capacity is necessary to serve approximately 40 percent of the peak day requirement of the average customer (TEC Brief at 15-16).

4. Analysis and Findings

The Department agrees that the availability of downstream capacity is a critical element of any firm transportation program in Massachusetts. The record shows that Boston Gas's upstream capacity is not sufficient to meet the peak needs of its customers. Therefore, the

Department finds that the Company must provide transportation customers with reliable access to its downstream assets. The Department notes that the availability of downstream capacity would facilitate the development of an alternative general transportation program and would allow customers to self-balance. Accordingly, the Department directs Boston Gas to make available to converting firm sales customers, on a voluntary basis, each customer's respective pro rata share of downstream assets at cost-based rates consistent with the Company's method for allocating pro rata shares of upstream capacity.

The Department recognizes that not all customers may choose 100 percent of their pro rata share of downstream assets and agrees, in principle, with AIM's recommendation that margins earned from leasing the "excess" downstream assets should flow back to the remaining sales customers. Accordingly, to the extent that a converting sales customer does not wish to utilize 100 percent of the Company's downstream capacity, the Department directs Boston Gas to make the remaining resources available, and allocate any margins generated from leasing downstream assets in a manner consistent with that prescribed in D.P.U. 93-141-A. The Department finds this arrangement to be consistent with Department precedent, a reasonable method for mitigating "excess" downstream capacity costs, and an appropriate incentive for the Company to aggressively manage its downstream assets.

Lastly, the Department agrees with DOER's recommendation to direct Boston Gas to update its analysis of available downstream capacity on an ongoing basis. Accordingly, the Department directs Boston Gas to include in its monitoring and evaluation reports described in Section X.D.4, below, a summary of the available downstream capacity, the amount of capacity necessary to serve remaining sales customers's needs, the number of transportation customers acquiring downstream assets, the volumes of capacity acquired by these customers,

and the total volumes of and total revenue generated from the downstream capacity purchased on the open market.

D. Monitoring and Evaluation

1. The Company's Proposal

The Company proposed to provide annual checkpoints, in conjunction with its annual compliance filings under its price cap plan, to provide the Department with the ongoing status of its exit from the merchant function, including the number of customers electing to purchase supply service from an aggregator, the number of aggregators currently operating in its service territory, and the volume of capacity assigned to the market (Exh. BGC-1, at 20).

2. DOER's Proposal

DOER proposed that certain reporting requirements concerning the changing market structure should be provided to the Department for review by interested parties (Exh. DOER-71, at 24). Specifically, DOER recommended the Department require Boston Gas to prepare quarterly and annual reports on the following: (1) number of customers converting from sales to transportation; (2) number of marketers qualified to operate on the Boston Gas system; (3) number of marketers operating and their respective share of industrial, commercial, and residential markets; (4) volume of capacity released to marketers at maximum rates; (5) the volume of capacity released via the auction process at discounted rates; (6) projected stranded costs; (7) requests by customers to return to sales service; (8) annual assessment of system operations; and (9) annual assessment of resources required for system balancing (id.).

DOER also addressed the issue of market power. Specifically, DOER stated that frequent reporting of marketer activity is important in determining whether true and

sustainable competition is developing or whether modifications to the Company's unbundling plan are necessary (id.). To this end, DOER recommended requiring the Company to also provide an annual written evaluation on the success or failure of its efforts to unbundle services and expand competition to all retail customers (id. at 24-25).

3. Positions of the Parties

a. DOER

DOER emphasizes the need for Boston Gas to file quarterly and annual reports regarding how well unbundling is working (DOER Brief at 61). DOER argues that such information, (as described in Section XI.D.2, above) would help ensure that the transition to a competitive market is a smooth one (id.).

b. TMG

TMG emphasizes that the Department should require Boston Gas to submit a monthly or quarterly report and to release information publicly concerning the market penetration (by volumes, type of customers, and numbers of customers) of Boston Gas's affiliate(s) into Boston Gas's service territory, including a "blind" (i.e., no names) delineation of the market shares of all other marketers doing business behind Boston Gas's city gate (TMG Brief at 48).

c. AIM

AIM recommends that Boston Gas be required to provide to the Department information on a bi-annual basis regarding the number of marketers at each take station and their respective market share (AIM Brief at 23). AIM's concern is that a small number of marketers could gain sizable market share at a take station and in effect become an oligopoly, and thus there should be checkpoints along the way to ensure that customers are adequately protected without discouraging the development of full and fair competition (id.).

d. TEC

TEC recommends that the Department impose conditions on any capacity allocation program so that the concentration of primary firm capacity of a single entity at a city gate would be limited to 20 percent (TEC Brief at 21-23). TEC argues that this is the same percentage FERC used in connection with its market power tests to allow utilities's affiliates to charge market-based rates (id. at 21, citing Entergy Services, Inc., 58 FERC ¶ 61,234.FN.79 and at ¶ 61,760 (1992). TEC adds that the Department should require the Company to condition any pilot release program at FERC so that any above maximum FERC rate capacity release would only apply to an entity that directly or indirectly controls no more that 20 percent of any city gate (id. at 23).

e. The Company

In response to the intervenors's concerns about the potential for suppliers gaining control of individual take stations and holding customers served from those stations hostage, the Company proposes to provide annual information through the transition period (Company Reply Brief at 6). Specifically, the Company proposes to provide a report to the Department on the number of customers who had migrated to firm transportation and the number of active marketers serving Boston Gas's customers (id.). The Company also states that it would include in these annual reports information as to the market concentration of third-party suppliers at individual take stations (id. at 6).

4. Analysis and Findings

The record shows that the Company agreed to provide a report on the progress of its unbundling efforts. The Department finds that this would be a reasonable step to monitor the impact of the approved unbundling plan. The Department further finds that this would also

facilitate the Department's decision-making process in Phase II. Accordingly, the Department directs Boston Gas to file such report by June 30, 1997. This report should contain the following information for the period December 1, 1996 through May 31, 1997, by month and in aggregate: (1) number of customers both electing to purchase supply service from aggregators and managing their own gas supply needs; (2) number of aggregators currently operating in the Company's service territory; (3) volume of upstream pipeline and storage capacity assigned to the market by marketer, customer class, and take station; and (4) number of customers requesting to return to sales service. In addition, the Department expects the Company to file information regarding the impact of its downstream capacity assignment plan, as directed in Section X.C.4, above. The Department notes that the Company is expected to collect this information throughout the interim period.

E. Implementation Schedule

1. The Company's Proposal

Boston Gas stated that in order to implement the full unbundling of gas sales from its distribution services it proposed, inter alia, the following schedule: (1) as of December 1, 1996, all firm sales C&I customers would be eligible for unbundled firm transportation service; and (2) as of November 1, 1997, all firm residential customers would be eligible for unbundled firm transportation service (Exh. BGC-1, at 6).

2. DOER's Proposal

DOER proposed to delay the opening of non-daily metered transportation service for C&I customers until April 1, 1997 for several reasons (Exh. DOER-71, at 6). DOER further proposed to move up the start date for residential transportation service to April 1, 1997, so that it coincides with the start date for C&I service (id. at 8).

3. Positions of the Parties

a. DOER

DOER reiterates its recommendation that the Company delay the implementation of transportation service to C&I customers until April 1, 1997, and move up the starting date for residential transportation service to April 1, 1997 (DOER Brief at 57-58). DOER emphasizes that customers should be informed fully of the service offerings before being offered transportation service (id. at 57). DOER states that the record suggests that customer education would be a lengthy process, and additional time for education can be used productively (id.). In addition, DOER argues that there is no reason to delay transportation service for residential customers until November of 1997 (id. at 58).

b. ComGas

ComGas asserts that the gas industry in Massachusetts is now at a critical crossroads, and cautions the Department to evaluate overall market structures, with respect to capacity assignment and release, before making irreversible decisions (ComGas Brief at 2-3). To this end, ComGas calls for the Department to establish a systematic procedure to examine the role of various market players in an unbundled gas market (id. at 5-6).

c. Essex

Essex advocates that the Department must first define the structure of the market it seeks to implement and then rule on company-specific proposals (Essex Brief at 2, 15). Accordingly, Essex recommends that the Department pursue, either in Phase II of this case or a generic proceeding, a comprehensive review of the impact of alternative market structures

on gas consumers in Massachusetts (id. at 3).[104] Essex argues that only after these issues are examined and successfully resolved should a permanent capacity release program be implemented (id. at 4).

d. Enron

Enron supports the unbundling schedule proposed by Boston Gas for its C&I and residential customers, and would not oppose implementing residential unbundling in April 1997 (Exh. ECT-1, at 3).

e. TMG

TMG supports Boston Gas's proposed date of December 1, 1996 to begin offering unbundled transportation services to C&I customers (TMG Brief at 46; TMG Reply Brief at 6). Regarding offering unbundled transportation services to residential customers, TMG recommends that, at the very least, Boston Gas be allowed to open this market on November 1, 1997 (TMG Brief at 47; TMG Reply Brief at 6). To this end, TMG requests that the Department mandate a residential unbundling roundtable - including all stakeholders - to help ensure the submission of consensually-developed residential unbundling tariffs, terms and conditions, and customer information plans (TMG Brief at 47).

f. Texas-Ohio

Texas-Ohio stated that it supports Boston Gas's proposed start date of December 1, 1996 for gas transportation to all C&I customers (Exh. TOG-1, at 14). Texas-Ohio stated that this date is not only feasible, but desirable in getting competition off the ground (id.). However, Texas-Ohio stated that a coordinated start date for C&I and residential customers,

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104 Essex states that this review should, at a minimum, address a number of key issues, including: the obligation to serve, supplier of last resort, primary deliver points, portfolio management, and stranded costs (Essex Brief at 3-4).

as proposed by DOER, would likely produce little benefit for the residential customers and result in significant additional confusion (id. at 14-15).

g. AIM

AIM states that commencing availability of transportation service on December 1, 1996, would result in large numbers of customers switching to transportation service at the closing date of sales service (AIM Brief at 18). AIM contends that there is not sufficient time to educate customers nor evaluate marketers who will be selling gas in the Company's territory (id.). Accordingly, AIM recommends that the Company should be allowed to begin offering transportation service to both its C&I and residential customers beginning April 1, 1997 (id. at 19).

h. The Company

Boston Gas states that it chose a phased approach to unbundling its C&I and residential customers for several reasons (Company Brief at 9). First, the Company states that some of its C&I customers are ready to transport now, and will most likely wish to take advantage of potential cost savings during the 1996/97 winter season (id. at 9-10). Second, the Company sees advantages in testing its processes and systems and gaining experience with its C&I customers before opening up its system to all customers (id. at 10). Third, the Company argues that its mandatory assignment program does not create a bias toward customers choosing to migrate sooner rather than later (id.). Lastly, the Company expresses its commitment to an educational campaign to ensure that customers are well informed to make necessary choices about the gas supplier (id.).

The Company argues that DOER, in proposing a coordinated start date, ignores the practical considerations surrounding the unbundling schedule, as well as the Company's stated

interest in gaining experience with unbundling on a smaller scale before opening to the larger class of residential customers (id. at 11). In addition, the Company asserts that AIM overlooks the fact that the Company's plan does not force any customers to make choices they do not fully understand (Company Reply Brief at 5). Therefore, Boston Gas concludes that there is no reason to preclude C&I customers who are ready to transport from doing so as soon as possible (Company Brief at 11; Company Reply Brief at 5).

4. Analysis and Findings

The Department agrees with the Company that there would be advantages in testing its administrative processes and operational systems and gaining experience with its C&I customers as soon as possible. The Department also finds that, consistent with our criteria for approving a capacity assignment plan, customers who are ready to transport now, and wish to take advantage of potential cost savings during the 1996/97 winter season, should be given the opportunity to do so. The Department finds that Boston Gas's proposed C&I unbundling schedule would better ensure that the interim transition toward a competitive gas supply market is expeditious, orderly, and minimizes customer confusion during the interim period. Accordingly, the Department approves the commencement of a C&I unbundling program on December 1, 1996, to run through the issuance of a Phase II Order.

The Department acknowledges certain intervenors's recommendations to establish a forum for reviewing generic residential unbundling issues. Accordingly, the Company directs Boston Gas not to file a Phase II proposal until the Department provides all parties with guidance on how we intend to proceed with Phase II.

XI. THE COMPANY'S PROPOSED PBR PLAN

A. Overview

The Company's performance-based regulation ("PBR") proposal is comprised of two elements: (1) a price cap plan that would be applied to the Company's monopoly services; and (2) a proposed PBR plan that would apply to competitive services provided by the Company, i.e., those services for which competitive alternatives exist (Tr. 3, at 93-96). This second element includes the Company's proposals for: (1) streamlined review of optional tariffs and non-core contracts; (2) margin sharing associated with non-core firm sales, interruptible sales, capacity release, and off-system sales; (3) buyout of interruptible transportation market; and (4) depreciation flexibility.

The Department addresses issues associated with the competitive element of the proposed PBR plan in this section of the Order. The proposed price cap plan is addressed in Section XII, below.

B. Standard of Review

The Department has established (1) a standard of review that would be applied to PBR proposals, and (2) the criteria by which to determine whether the standard has been met. See Incentive Regulation at 52-66. The Department stated that, because incentive regulation acts as an alternative to traditional cost of service regulation, incentive proposals would be subject to the standard of review established by G.L. c. 164, § 94, which requires that rates be just and reasonable. Id. at 52. A petitioner seeking approval of an incentive proposal is required to demonstrate that its approach is more likely than current regulation to advance the Department's traditional goals of safe, reliable and least-cost energy service and to promote

the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation. Id. at 57.

The Department further stated that well-designed incentive mechanisms should provide utilities with greater incentives to reduce costs than currently exist under traditional cost of service regulation and should result in benefits to customers, whether in the form of lower prices or increased service, which are greater than would be present under current regulation. Id. at 54-55. The Department added that a well-designed incentive plan should provide a utility with the opportunity to earn greater rewards in exchange for the assumption of greater risk. Id. at 57.

In addition to these general criteria, the Department established more specific criteria to be used in evaluating incentive proposals. These criteria require that incentive proposals:

(1) must comply with Department regulations, unless accompanied by a request for a specific waiver. The Department added that incentive proposals that comply with statutes and governing precedent are strongly preferred;

(2) should be designed to serve as a vehicle to a more competitive environment and to improve the provision of monopoly services. Incentive proposals should avoid the cross-subsidization of competitive services by revenues derived from the provision of monopoly services;

(3) may not result in reductions in safety, service reliability or existing standards of customer service;

(4) must not focus excessively on cost recovery issues. If a proposal addresses a specific cost recovery issue, its proponent must demonstrate that these costs are exogenous to the company's operation;

(5) should focus on comprehensive results. In general, broad-based proposals should satisfy this criterion more effectively than narrowly-targeted proposals;

(6) should be designed to achieve specific, measurable results. Proposals should identify, where appropriate, measurable performance indicators and targets that are not unduly subject to miscalculation or manipulation; and

(7) should provide a more efficient regulatory approach, thus reducing regulatory and administrative costs. Proposals should present a timetable for program implementation and specify milestones and a program tracking and evaluation method.

Id. at 58-64.

C. Service Baskets

1. Introduction

a. Description of Current Services

Boston Gas's services are currently classified as either core or non-core. The Company classified its services in this proceeding in the same manner as in Boston Gas Company, D.P.U. 92-259 (1993), i.e., core services are provided to customers who have no alternative to gas energy use, and non-core services are provided to customers who have alternative energy sources (Tr. 3, at 94-95, 100). Boston Gas stated that it targets its tariffed rates toward the core market, while its special contracts meet the needs of non-core customers (id. at 94).[105] For purposes of determining which services would be subject to the price cap mechanism, Boston Gas proposed to separate its core and non-core services into two baskets: (1) a monopoly services basket; and (2) a competitive services basket (Exh. BGC-3, at 35).

b. Monopoly Services Basket

The monopoly services basket would include all tariffed services, and would be subject to the price cap formula (Exh. BGC-3, at 35-36; Tr. 3, at 92).

c. Competitive Services Basket

Under the Company's proposal, Boston Gas would determine which of its services would be considered a competitive service and thus not require prior Department approval

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105 Boston Gas noted that some non-core customers with alternative fuel capacity are currently being served under tariffed rates at the customers's choice (Tr. 3, at 94).

(Exh. BGC-3, at 36). Rates charged for services in the Company's competitive services basket would not be subject to the price cap formula, and the margins earned from these services would be retained by the Company (id.). Currently, the Company's competitive services basket includes its standard offer contracts for interruptible transportation from the city gate to the burner tip provided pursuant to D.P.U. 93-141-A (1996) and its VNG service (id.).[106] Boston Gas stated that it anticipates developing new competitive services to provide additional choices and service options to customers (id.). By way of illustration, the Company noted that, in the future, it may propose contracts and optional tariff services for non-core customers that would be subject to Department approval (id.). Boston Gas stated that in order to protect core customers from subsidizing discounted service to non-core customers, the Company would bear the risk for any discounts whether service is provided under contract or tariff (id. at 38).

Additionally, Boston Gas stated that it contemplates providing other services, such as equipment financing plans, which would be part of its competitive basket (Exh. BGC-3, at 36; Tr. 7, at 183). The Company also indicated that the implementation of these services would not require prior Department approval (Exh. BGC-3, at 36).

d. Other Services and Rate Elements

The Company proposed that all of its core and non-core services be subject to its price cap mechanism, with the following exceptions: (1) firm, tariffed merchant service at the city

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106 The Company reported that it has ceased making firm city-gate sales under the non-core contracts entered into pursuant to D.P.U. 92-259, because it determined that the continuation of this service is inconsistent with its proposal to exit the merchant function (Exh. BGC-1, at 16). In order to serve existing contract customers, Boston Gas entered into a sale for resale arrangement with AllEnergy (Exh. BGC-1, at 16). This is currently the subject of investigation in D.P.U. 96-66.

gate; (2) interruptible sales at the city gate; (3) sales for resale; (4) capacity release; (5) energy audit services recovered through the energy conservation charge as mandated by statute;[107] (6) manufactured gas remediation costs being recovered through the CGAC; (7) the Company's proposed DSM programs; and (8) firm transportation service to Distrigas (id. at 34; Tr. 3, at 95).[108]

2. Positions of the Parties

a. DOER

DOER notes two concerns related to the Company's proposal to retain all revenues generated by its competitive operations. First, DOER argues that when evaluating the overall risks and rewards under the Company's plan, the Department must take into consideration the gains accruing to shareholders (DOER Brief at 11). Second, DOER argues that if Boston Gas is allowed to retain all the margins associated with competitive services, then it must demonstrate that ratepayers will not bear any of the costs associated with such services (id.). Specifically, DOER notes that the Company has booked certain direct and indirect expenses related to its VNG operations, which DOER contends should be excluded from the "cast-off" rates (id. at 11-12).

b. AIM

AIM argues that the Company's proposal to place services in its competitive basket without Department approval should be rejected (AIM Brief at 12). AIM contends that the ability of Boston Gas to determine which services are competitive, combined with other

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107 G.L. c. 164, App. 2-1 et seq.

108 Boston Gas stated that the ratemaking treatment of a number of these services and expenses would be addressed by the LDAC proposed in this proceeding (Exhs. BGC-3, at 35; BGC-75, at 28).

elements of Boston Gas's price cap mechanism, ensures annual rate increases to customers while reducing the probability that service improvements can be achieved through greater efficiencies (id.).

c. MOC

MOC argues that the Company should not be permitted to engage in competitive services while it provides monopoly services (MOC Brief at 31-32). MOC contends that the Company's monopoly status gives it a commanding position in the market, by virtue of customer information, marketing leads, market presence and name recognition (id. at 33). According to MOC, Boston Gas is able to produce and maintain an "unbeatable" pricing advantage by virtue of its access to the resources acquired and used to provide monopoly service (id. at 33-34). Furthermore, MOC argues that no accounting formula or cost allocation mechanism can account for the Company's name recognition or marketing efforts (id. at 34).

As a solution, MOC proposes that, if the Company is to be permitted to reap the benefits of competition, then Boston Gas must provide its competitive services through a separate subsidiary or affiliate which is independently operated and subject to the rules of affiliate conduct adopted in the ongoing proceeding in D.P.U. 96-44 (id. at 31-32). According to MOC, this approach would provide benefits by: (1) removing the Department and regulated monopolies from areas where competition is functioning; (2) ameliorating the disproportionate advantage held by utilities against smaller competitors; (3) limiting ratepayer risk by placing nonregulated business risks upon shareholders; (4) allowing competitors to pursue antitrust complaints in court; and (5) ensuring that ratepayers do not subsidize unregulated ventures (id. at 32).

d. The Company

Boston Gas argues that it has appropriately separated its services into monopoly and competitive baskets as part of its price cap implementation proposal, in a manner consistent with the Department's findings in D.P.U. 94-50 (Company Brief at 74, citing NYNEX at 204). The Company observes that no party in this proceeding has objected to the classification of services in its competitive basket (id. at 75). Furthermore, Boston Gas claims that the objections raised to its determination of the contributions made by competitive services are confined to the valuation of the Company's IT market (id.).

3. Analysis and Findings

Regarding AIM's objections to the Company's discretion in assigning services to its competitive basket, we note that utilities are engaged in a wide variety of programs that could be considered an element of a competitive basket, including appliance sales and rentals, cogeneration equipment sales, and propane operations. D.P.U. 92-111, at 80; D.P.U. 90-121, at 20; D.P.U. 87-59, at 6-7; D.P.U. 1580, at 77.[109] While the Department previously has not required utilities to obtain approval prior to engaging in nonregulated operations, it has evaluated service offerings which were deemed to be competitive services. See, e.g., NET-NOVA Centrex, D.P.U. 85-90 (1985); NET-Centrex, D.P.U. 84-82 (1984). Cf. Fall River Gas Company, D.P.U. 11655 (1956) (Department approval required pursuant to G.L. c. 164, § 17A to invest in a subsidiary company organized for purpose of separating nonutility operations from gas distribution operations).

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109 The Company itself operated an appliance rental business until 1987. D.P.U. 88-67, Phase I at 78.

Although the record evidence indicates that certain potential service offerings identified by Boston Gas would reasonably be considered competitive services, the distinction between monopoly and competitive service may not be as clear for other potential services. While Boston Gas may represent that a proposed service offering is directed toward the competitive market, the Department may act on its own motion pursuant to G.L. c. 164, § 94, or upon complaint pursuant to G.L. c. 164, § 93, to investigate Boston Gas's service offerings to determine whether they are related to monopoly or competitive service. Accordingly, the Department finds that our statutory authority provides sufficient assurance that the Company's new service offerings would be appropriately classified.

In order to ensure that any new service offerings are appropriately classified by Boston Gas, the Company is hereby directed to submit to the Department in writing a description of any new service offerings, at least four weeks prior to the implementation of the service. Our intent here is not to place an administrative burden on the Company in the operation of its competitive activities, but to ensure that services are appropriately classified.[110]

With respect to MOC's arguments concerning what it perceives as the potential for anticompetitive behavior by Boston Gas, the Department has examined anticompetitive effects in cases where the anticompetitive action was alleged to be integrally related to the very prices set by the Department in its ratemaking function. NET-V-Path, D.P.U. 88-13, at 17 (1988). However, the Department has asserted no active role in setting the price charged by utilities in the conduct of their nonutility operations. The Department has relied on incremental cost analysis for nonutility operations to ensure that ratepayers are not harmed by the existence of

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110 As a practical matter, the Department anticipates that virtually all service offerings proposed by the Company would be readily identifiable as either a monopoly or competitive service.

these activities and may in fact receive substantial benefits from the profits earned. See, e.g., Bay State Gas Company, D.P.U. 89-81, at 72-76 (1989); D.P.U. 87-122, at 24.

The Department recognizes that the ability of Boston Gas to recover costs through its regulated activities conceivably could have an impact on its competitive position vis a vis trade competitors. While it is possible that the creation of a separate subsidiary by Boston Gas could address the concerns raised by MOC, we note that our decision in D.P.U. 96-44 may assist in resolving, or in reducing the scope of, issues to be considered. Furthermore, the record in this proceeding contains no evidence to evaluate the required structure of the entity which MOC seeks, the scope of services the entity would provide, or the financial investment that would be required by Boston Gas.[111] Accordingly, at this time the Department declines to direct the Company to separate its nonutility operations through a separate subsidiary.

The Department has reviewed Boston Gas's selection of services that would be assigned to its monopoly or competitive basket, and therefore excluded from its PBR proposal. Regarding the services and cost items which Boston Gas does not seek to include in its PBR, the Department has noted that broad-based incentive mechanisms, as proposed here, may not be able to fully address certain utility operations, such as DSM and environmental compliance. Incentive Regulation at 62. Additionally, statutory obligations may influence the ability of a utility to bring a particular function, such as the ECS program, under the PBR umbrella. Based on this record, the Department finds the Company's decision not to include its selected utility operations in its PBR mechanism to be reasonable and appropriate.

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111 Under G.L. c. 164, § 17A, any investment by the Company in such an entity would require Department approval.

Turning to the elements Boston Gas proposes to include in its monopoly basket, the Department finds that the Company's tariffed services are clearly monopoly services. Accordingly, the Department finds that the Company has appropriately classified the elements of its monopoly basket.

The Department has reviewed Boston Gas's selection of services to be assigned to its competitive services basket. Regarding the Company's D.P.U. 92-259 contracts, the Department previously has found that these are designed to serve a competitive market. D.P.U. 92-259, at 21. Accordingly, these contracts shall be assigned to the Company's competitive services basket.[112] With respect to the Company's VNG service, the Department also has found that this service is designed to operate in competitive market along with other "clean" fuels, as defined by 42 U.S.C.A., § 7581(2). D.P.U. 92-230, at 28. Therefore, the Department finds that this service also shall be assigned to the competitive services basket.

Regarding Boston Gas's proposed assignment of IT service to its competitive basket, the Department has rejected the Company's proposed buyout of IT service. See Section IX.A.3, above. Moreover, the Department is unpersuaded that IT service should be treated as a competitive service. While city gate gas service has some elements of market competition, in that customers may choose from a range of competing suppliers, a utility's distribution function, including transportation, remains a monopoly service. D.P.U. 91-143-A at 13. As a monopoly service, transportation service requires some degree of regulation in order to prevent cross-subsidization of interruptible customers by core customers. Id. at 14. On this basis, the Department finds that it is inappropriate to assign IT service to the Company's competitive basket.

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112 As noted above, the Company has terminated service under these contracts.

The Department also does not consider IT service to be an element of Boston Gas's monopoly basket. The Department has reaffirmed that IT service is an opportunity-driven transaction to which it is inappropriate to apply cost-based pricing principles. Id. at 39. Therefore, it would be inappropriate to assign IT service to the Company's monopoly basket. Accordingly, the Department finds that the Company's IT service does not constitute an element subject to the provisions of the price cap.

The Department has approved the creation of an LDAC intended to recover certain local distribution-related costs presently recovered through the CGAC. Section VII.B, above. Consistent with the treatment of IT margins associated with the Company's service to Distrigas in the LDAC, the Department finds that IT margins shall be flowed back to core sales and transportation customers through the LDAC approved in this Order.

D. Streamlined Tariff Review

1. Introduction

The Company requested a streamlined regulatory process pertaining to the filing of non-core optional tariffs and non-core contracts (Exh. BGC-3, at 38). Boston Gas stated that in order to compete with unregulated oil dealers, it is imperative that it be able to finalize local transportation agreements in an expeditious manner, and allow the customer to couple these agreements with gas marketing arrangements (id.). Therefore, the Company proposed that the Department approve LDC transportation services and interruptible transportation contracts within five business days of filing (id.). As part of these filings, Boston Gas said that it would provide a description of the customer's competitive alternatives and demonstrate that the tariff or contract price exceeds the relevant marginal cost floor price (id. at 39).

2. Position of the Company

The Company argues that such treatment is consistent with the Department's tariff review process applied in D.P.U. 92-259 (Company Brief at 78-79). Boston Gas claims that a streamlined regulatory process is necessary to enable the Company to finalize competitive transactions expeditiously and to compete successfully with alternative energy providers (id. at 79). The Company pledges to file supporting evidence with its proposed tariff and contract documenting the customer's competitive alternatives and demonstrating that the filing exceeds marginal cost (id.). No other parties addressed this issue.

3. Analysis and Findings

In evaluating the proposed regulatory review of the Company's proposed non-core optional service tariffs and non-core contracts, the Department must determine (1) whether the proposed five business day review period is appropriate, and (2) whether the proposed filing format would provide sufficient documentation to support the Company's actions under its proposal without being unduly burdensome.

Tariff filings by gas, electric, and water utilities are subject to the provisions of G.L. c. 164, § 94, which reads in pertinent part:

> Unless the [D]epartment otherwise authorizes, the rates, prices and charges as set forth in such a schedule shall not become effective until the first day of the month next after the expiration of fourteen days for the filing thereof.

Special contracts are also subject to the provisions of G.L. c. 164, § 94, which reads in pertinent part:

> Unless the [D]epartment otherwise orders, all contracts for the sale of gas or electricity by gas or electric companies, except contracts for sale by a company whose sole business in this [C]ommonwealth is the supply of electricity in bulk, shall be filed with the [D]epartment and shall not become effective until thirty days after filing.

The statute permits the Department some latitude in approving tariffs and contracts in less than the statutory period. In D.P.U. 92-259, at 101-103, the Department approved the Company's proposal for a flexible review process for a discrete group of special customers meeting specific requirements for a finite period of time, with the opportunity to review and reevaluate the contract process after two years. In this case, the Company seeks expedited regulatory review of what could constitute a wide variety of tariffs and special contracts, which may have features that do not lend themselves to review within five business days. Moreover, the price cap mechanism being approved herein does not make specific provision for post-hoc review of these contracts.

Under these conditions, we find that it would be inappropriate for the Department to relinquish its authority to suspend the effective date of a tariff or contract during investigation. The Department's approval of Boston Gas's price cap does not diminish any regulatory responsibilities imposed pursuant to statute. The Department must be able to exercise its judgment in determining whether a tariff filing warrants suspension and investigation. NYNEX at 257-258.

Despite our refusal to adopt the Company's proposal for approval on an expedited basis, the Department is sensitive to the need for Boston Gas to compete effectively in the non-core market. D.P.U. 92-259 at 35-36. Consequently, the Department finds that the competition faced by Boston Gas justifies a more flexible and responsive regulatory review process. Accordingly, the Department will exercise its discretion to grant requests for expedited review of tariffs and contracts on a case-by-case basis, taking into account, inter alia, compliance with Department regulations, the sufficiency of the supporting information provided by the Company, and the pricing rules of the price cap.

E. Margin Sharing

1. The Company's Proposal

Under the Company's current CGAC, 75 percent of all margins above a pre-established threshold that are associated with non-core firm sales, interruptible sales, capacity release, and off-system sales are flowed back to firm sales customers. D.P.U. 93-141-A at 67; D.P.U. 93-141-B at 5; D.P.U. 93-60 at 298, 325. Similarly, 75 percent of all margins above a set threshold associated with IT are passed back to firm sales and transportation customers. D.P.U. 93-141-A at 64-65.

Boston Gas proposed to revise its current CGAC ratemaking treatment for interruptible sales at the city gate, sales for resale, and capacity release (Exhs. BGC-1, at 16; BGC-3, at 34). For these three services, the Company proposed to replace the 75/25 sharing mechanism with a passback of 100 percent of earned margins through the CGAC to firm sales customers as a credit to customers's gas costs, and will cease making firm sales of gas at the city gate under authority granted by the Department in D.P.U. 92-259 (Exhs. BGC-1, at 16; BGC-3, at 34).

2. DOER's Proposal

To mitigate stranded costs, DOER proposed requiring Boston Gas to credit revenues from capacity release and off-system sales made using its merchant portfolio, revenues from IT, and revenues from the release of downstream assets, at market-based rates (Exh. DOER-71, at 18). According to DOER's proposal, Boston Gas would be given a reasonable opportunity to recover these and any remaining stranded costs not fully offset by these revenue credits (id.).

3. Analysis and Findings

In the Company's last rate case, the Department approved a 75/25 sharing above a set threshold of margins resulting from non-core firm sales, interruptible sales and transportation, capacity release, and off-system sales. D.P.U. 93-60 at 298, 325. While the Department reaffirmed this margin-sharing arrangement for all LDCs in D.P.U. 93-141-A at 64-65 and D.P.U. 93-141-B at 5, we noted that margin sharing represents a targeted incentive of the type generally discouraged in Incentive Regulation, and allowed the margin sharing to remain in effect as an interim measure until the respective utilities's next general rate cases or incentive rate proposals. D.P.U. 93-141-A at 62.

The Company has proposed to supplant its current margin sharing arrangement by flowing back all margins associated with interruptible sales, capacity release, and sales for resale to firm sales customers. The Department has approved in this Order a broad-based incentive mechanism which is more consistent with the transition to a competitive marketplace than the targeted incentive mechanisms approved in both D.P.U. 93-60 and D.P.U. 93-141-A. However, the Department finds that it is premature at this time to allow Boston Gas to flow back to firm sales customers 100 percent of the Company's margins earned on these transactions. As described in Section X.A.4, above, the Department has approved an interim C&I capacity assignment program. Under this arrangement, the Company will be required to continue to manage a significant portion of its commodity and capacity portfolio. The Department finds that a margin-sharing arrangement, as ordered in D.P.U. 93-60 and D.P.U. 93-141-A, remains an appropriate incentive for the Company to mitigate the cost of this portfolio which it holds to serve its remaining firm sales customers. Accordingly, the

Department directs Boston Gas to maintain its existing margin-sharing arrangement for interruptible sales, off-system sales, and capacity release.

As described in Section X.B.3, above, the Department has approved the mandatory assignment on an interim basis of Boston Gas's Canadian supply contracts on a sale for resale basis.[113] In doing so, the Department expects the Company to price these assets at Boston Gas's actual cost, thus generating no margins. The Department directs the Company to return to firm sales customers 100 percent of the revenues generated from the assignment of Canadian supplies to marketers under the approved interim capacity assignment plan, through the operation of the CGAC. In addition, the Department directs the Company to return to firm sales customers margins generated from the marketing of excess supplies outside Boston Gas's service territory, using the margin-sharing arrangement for off-system sales approved in D.P.U. 93-141-B at 5.

With respect to margins generated from the lease of downstream capacity, the Department directs the Company to apply the margin-sharing arrangement applicable to capacity release in D.P.U. 93-141-A, returning 75 percent of margins to firm sales customers.

F. Depreciation Flexibility

1. Introduction

Boston Gas notes that under a price cap, the Company would assume all of the risk associated with its investment decisions (Exh. BGC-3, at 33). In recognition of that risk,

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[113] For purposes of this Order, the Department considers the Canadian supply contracts as separable into three components: (1) supplies which marketers are assigned under the Company's mandatory capacity assignment plan approved herein; (2) supplies used to serve existing firm sales customers; and (3) excess supplies that Boston Gas would market outside its service territory to mitigate the overall cost of its supply portfolio.

Boston Gas requested that the Department grant the Company the ability to adjust its depreciation accrual rates for investments in new competitive services so that the book accrual rates match those used for income tax purposes, as specified by the Internal Revenue Service (id. at 33-34; Exh. DPU-107). The Company's proposal does not apply to its core monopoly distribution services or any of its current nonregulated services, but would apply to plant equipment associated with future ventures into nonregulated activities (Tr. 3, at 62, 89-90; Tr. 16, at 55-59).[114] For example, the Company stated that if it were to offer a financing service for its customers, it would seek depreciation flexibility for the associated plant investment (Tr. 16, at 56).

2. Positions of the Parties

a. Attorney General

The Attorney General agrees with Boston Gas's proposal for depreciation flexibility, to the extent that the assets subject to depreciation flexibility are not part of the Company's gas distribution operations and are neither directly nor indirectly charged back to gas distribution operations (Attorney General Brief at 13-14; Attorney General Reply Brief at 14).

b. The Company

Boston Gas contends that depreciation flexibility would not be applied to assets used in its gas distribution business, but only to those assets used in those competitive ventures it may enter into after the date of this Order (Company Brief at 73-74). The Company notes that it would continue to seek to apply the Department-approved accrual rates for its gas distribution assets (id. at 74). Boston Gas further states that it will not make changes in its accounting

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[114] The Company's prefiled testimony on this point implies that Boston Gas is seeking depreciation flexibility for all of its services, including its gas distribution operations. See Exh. BGC-3, at 33-34.

practices for the sole purpose of enhancing reported earnings, and that any proposed accounting changes affecting its gas distribution operations would be subject to Department approval (id.).

3. Analysis and Findings

The Department's policies and precedents on depreciation apply to regulated operations. The Company's requested depreciation flexibility would be applied only to future plant investment intended for use in nonregulated operations entered into after the date of this Order. If Boston Gas were to transfer assets used in its regulated operations to nonregulated operations, or to use those regulated assets in its nonregulated operations, the Department's treatment of those transactions would continue to be governed by our nonutility allocation policy. D.P.U. 90-121, at 20-70; D.P.U. 86-33-G at 113-201; D.P.U. 87-59, at 10. The Department finds that its affiliated transaction allocation policy provides adequate protection against the subsidization of nonregulated activities by ratepayers. Accordingly, the Department allows the Company to apply depreciation accrual rates for nonregulated operations entered into after the date of this Order, to the limit prescribed by the Internal Revenue Service for tax purposes. The Company is hereby directed to book its depreciation accruals for these assets to Account 266 (Reserve for Depreciation and Amortization of Nonutility Property). 220 C.M.R. §§ 50.00 et seq..

XII. THE COMPANY'S PRICE CAP PROPOSAL

A. Introduction

As stated in Section IV.A, above, the primary component of Boston Gas's PBR proposal is a price cap plan that would apply to the rates of its monopoly services (i.e., its tariffed transportation services) (Exh. BGC-3, at 35-36). The price cap plan would allow the

Company to adjust annually its distribution rates by a factor that would reflect price inflation offset by a factor that would reflect projected productivity gains (id. at 10). In addition, the proposal would allow the Company to adjust its rates to account for (1) costs that are outside of the Company's control, i.e., exogenous costs, and (2) changes in the Company's cost of capital. Finally, the proposal would require the Company to adjust its rates downward if it did not meet specified customer service performance standards (id.).

The Company proposed that the price cap plan be implemented for a term of five years, from December 1, 1996, through November 30, 2001 (id. at 32). The plan would continue beyond 2001 unless (1) the Department, the Company, or other parties seek modifications to the plan, and (2) the Department determines that modifications are necessary (id.). For each year that the price cap is in effect, the Company would submit a compliance filing to the Department on September 15, for implementation of new rates on November 1 (id. at 47). The compliance filing would include, among other things, (1) the calculation of the price cap adjustment, including documentation associated with exogenous costs and capital cost changes, (2) the development of new rates consistent with the price cap, and (3) class by class bill impacts (id.).

The Company's proposed price cap plan is described in two parts: (1) the components of the proposed price cap formula -- the inflation index, the productivity offset, the exogenous cost factor, the service quality index, and the cost of capital adjustment; and (2) implementation aspects of the plan -- the term of the plan, the annual setting of individual rate elements within a rate class, and the accumulation of foregone rate increases.

B. The Price Cap Formula

1. The Company's Proposal

a. Introduction

Under Boston Gas's proposal, rates for the Company's monopoly services would be governed by the following formula:

$P_{(t)} \leq P_{(t-1)} * (1 + I_{(t)} - X \pm Z_{(t)})$, where

$P_{(t)}$ is the Company's weighted average price[115] in year (t);

$P_{(t-1)}$ is the Company's weighted average price in the year (t-1);

$I_{(t)}$ is a price inflation index for year (t);

X is a productivity offset that would remain constant throughout the term of the plan; and

$Z_{(t)}$ is an adjustment for exogenous costs that might occur in year (t).

(id. at 10-11).

The proposed plan would allow the Company to adjust the weighted average price yielded by the formula to account for (1) material changes in the cost of equity capital, and (2) a service quality index that would measure the Company's actual performance against a service quality benchmark established by the Company (id. at 11). The Department describes each of the components below.

115 The Company's weighted average price would be calculated using revenue and billing determinants normalized for weather and adjusted for savings from implementation of the Company's DSM programs.

b. Price Inflation Index

The Company proposed to base the price inflation index included in the price cap formula on the GDP-PI as measured by the U.S. Commerce Department (id. at 11).[116] The inflation index, which would be adjusted annually as necessary, would be calculated as the percentage change between the current year's GDP-PI and the prior year's GDP-PI. For each year, the GDP-PI would be calculated as the average of the most recent four quarterly measures of the GDP-PI as of the second quarter of the year (id. at 12).[117]

c. Productivity Offset

The Company proposed that the productivity offset, X, be calculated as:

$X = (TFP_{(NEgas)} - TFP_{(US)}) - (IP_{(NEgas)} - IP_{(US)}) + CD$, where

$TFP_{(NEgas)}$ is a productivity growth index for the Northeast gas distribution industry during the years, 1984-1994;

$TFP_{(US)}$ is a productivity growth index for the U.S. economy during the years, 1984-1994;

$IP_{(NEgas)}$ is an input price growth index for the Northeast gas distribution industry during the years, 1984-1994;

$IP_{(US)}$ is an input price growth index for the U.S. economy during the years, 1984-1994; and

CD is a consumer dividend factor.[118]

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116 The GDP-PI is a measure of the U.S. economy-wide inflation in the prices of final goods and services (Exh. BGC-10, at 6).

117 This information is published each September in the Survey of Current Business, a publication of the U.S. Commerce Department, Bureau of Economic Analysis (Exh. BGC-3, at 12).

118 The consumer dividend factor is referred to as a "stretch factor" in NYNEX.

The productivity offset would remain constant over the term of the price cap plan. (Exh. BGC-3, at 13-14; Exh. BGC-10, at 7).

The Company submitted a study, titled "Productivity Trends of U.S. Gas Distributors in the Provision of Gas Delivery Services" ("productivity study"), that measured the trends in productivity and input price growth, during the years 1984 through 1994, of local gas distribution companies ("LDCs") located both in the northeast United States ("regional LDCs") and in the nation as a whole ("nationwide LDCs") (See Exh. BGC-11).[119] The productivity study used a total factor productivity ("TFP") index to measure productivity growth (Exh. BGC-10, at 4). A TFP index, which measures the trend in an industry's unit costs that is not due to measured inflation in the prices of labor, capital, and other production, is intended to capture the net effect on unit cost of various industry developments, including technical change and growth in demand for the industry's products (id.). The TFP index was calculated as the ratio of an output quantity index to an input quantity index (id.). The output quantity index, which is intended to measure the trend in the gas delivery output of LDCs, was based solely on the number of gas delivery customers (Exh. BGC-11, at 3-4). The productivity study stated that, although variables such as gas delivery volume ("throughput") and maximum day sendout could have been included in the output quantity index, research shows that growth in the number of customers is the dominant output-related cost driver in the gas distribution industry (id. at 3-4, citing Exh. BGC-12). The input quantity index, which was calculated as the difference between the growth rate of total distribution-related costs and the input price index, is intended to measure the change in total distribution-related costs for

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119 The productivity study included a sample of 51 nationwide LDCs, of which 19 were located in the northeast (Exhs. BGC-10, at 3; BGC-11, Table 1).

reasons other than measured input price inflation (Exh. BGC-11, at 4). It was comprised of three categories - labor, capital, and miscellaneous (id. at 9).

The results of the study indicated that, for the period 1984-1994, the average growth in productivity for the regional LDCs was equal to -0.1 percent, while the average productivity growth for the nationwide LDCs was equal to 0.4 percent (id. at 12). For the same period, the average input price growth for regional LDCs was equal to 3.7 percent, while the average input price growth for the nationwide LDCs was equal to 3.1 percent (id.). For the U.S. economy, the productivity growth index was set equal to 0.3 percent, based on the multi-factor productivity index for the U.S. private business sector, as reported by the Bureau of Labor Statistics of the U.S. Department of Labor, and the input price growth index was set equal to 3.6 percent (Exh. BGC-3, at 14; Exh. BGC-10, at 7).

The Company calculated its productivity offset using the productivity and input price growth indices for the regional LDCs, rather than the nationwide LDCs, stating that the results of its productivity and cost-performance studies[120] demonstrate that there are structural cost differences between regional and nationwide LDCs that need to be reflected in the price cap formula (Exh. BGC-3, at 14-15, citing Exhs. BGC-11 and BGC-15). Inputting the results of the productivity study into the productivity formula, the Company calculated a productivity factor, not including the consumer dividend factor, equal to -0.4 percent (Exh. BGC-3,

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120 The Company submitted two cost-performance studies in this proceeding. These studies are titled, "The Cost Performance of Boston Gas in the Provision of Gas Delivery Services" ("Lowry cost study") and "A Statistical Benchmarking Study of Transportation Costs for Natural Gas Utilities" ("Berndt cost study"). They are marked as Exhibits BGC-12 and BGC-15, respectively.

at 14).[121] Finally, the Company proposed a consumer dividend factor equal to 0.5 percent, stating that the inclusion of such a factor was intended to ensure that its customers would benefit from the move to performance-based regulation (id. at 15-16). Using the information described above, the Company calculated an overall productivity offset equal to 0.1 percent (id. at 14).

The Company did not include an accumulated inefficiencies factor in its productivity offset, because it considered that the results of its cost-performance studies showed that the Company "is efficiently managed and that its pre-1995 costs were very much in line with the rest of the industry" (id. at 17-18).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that the Company's analysis of its productivity demonstrates that Boston Gas is currently and continues to be inefficient (Attorney General Brief at 12, citing Exh. BGC-10, at 11-12). The Attorney General maintains that Boston Gas's historical rate of change in productivity is less than the rest of the gas distribution industry (id. at 12, citing Exh. BGC-10, at 11-12). According to the Attorney General, the productivity studies performed by Dr. Lowry exhibited several flaws (id. at 18). First, the Attorney General argues that the individual company data used to perform the productivity studies include proprietary data that is not verifiable by the Department or other parties (id. at 18-19; Attorney General Reply Brief at 8). Therefore, the Attorney General suggests that

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121 The Company stated that it did not regard the 0.1 percent difference between the input price trends of the northeast LDCs and the U.S. economy to be significant. Therefore, the Company set the input price differential equal to zero (Exh. BGC-3, at 14; Exh. BGC-10, at 8).

the Department cannot approve the use of these results (Attorney General Brief at 18-19; Attorney General Reply Brief at 8). Second, the Attorney General claims that Dr. Lowry and Dr. Berndt incorrectly adjusted Boston Gas's data for 1993 and 1994 by removing costs that the Company views as non-recurring (Attorney General Brief at 19). The Attorney General maintains that this is inconsistent treatment unless a similar adjustment is made for all companies in the comparison group. Therefore, the Attorney General states that the results of the analysis are not reliable and that the Department should reject Dr. Berndt's conclusion that Boston Gas is not different from the other New England companies in terms of productivity (id.). Third, the Attorney General criticizes Dr. Lowry's use of the number of customers as the only output measure in his analysis (id., citing Exh. AG-11, Memo of July 17; Tr. 10, at 47-49). According to the Attorney General, the record demonstrates that gas volume is less susceptible to short-run demand shifts than the number of customers (Attorney General Reply Brief at 9). Therefore, the Attorney General states that adding a measure of output based on firm volumes is appropriate and improves the results of the analysis (Attorney General Brief at 19; Attorney General Reply Brief at 9). Fourth, the Attorney General points out that the analysis uses data for the years 1984 through 1994. Since 1995 information is now available, the Attorney General recommends that the Department base its analysis on the updated results using 1995 data (Attorney General Brief at 20). Finally, the Attorney General argues that a utility should not be allowed to incorporate negative productivity changes into future rates, assuming the Company wants to stay competitive in the national and international markets (Attorney General Reply Brief at 8-9).

The Attorney General characterizes the Company's proposed consumer dividend of 0.5 percent as minimal (Attorney General Brief at 21). Consequently, the Attorney General

recommends that the Department incorporate a productivity offset with a consumer dividend of one percent, which he maintains insures that the Company will set significantly higher goals (id. at 21-22, citing NYNEX at 165-166).

The Attorney General points out that in NYNEX, the Department found the following:

> If the telecommunications industry has been operating less efficiently during the long term period that is the foundation of the productivity offset than it would have under price cap regulation (a notion that must be acknowledged in order to accept price cap regulation as superior to ROR regulation in maximizing economic efficiency), then there must be accumulated inefficiencies that should be accounted for in the first term of a price cap plan.

(Attorney General Brief at 22, citing NYNEX at 166). According to the Attorney General, the analysis of Boston Gas's productivity is the same. Therefore, the Attorney General recommends that the Department incorporate an accumulated inefficiencies offset of 2.25 percent, recovered over five years, based on the difference between Dr. Lowry's calculated negative change in productivity for the gas distribution industry in the northeast and his calculated positive change in productivity for the nation's gas distribution industry, assuming that the same annual rates of change in productivity have been in existence for the last twenty years (id. at 23). Moreover, the Attorney General characterizes its recommended accumulated inefficiencies factor as "conservatively low," because his calculation is based on the assumption that the national group used in the calculation is as efficient as firms in the competitive marketplace, but that in reality, the companies in the national comparison group are substantially regulated (Attorney General Reply Brief at 10).

b. DOER

DOER states that it is imperative that the productivity factor provide the most realistic measure of what is likely to occur during the course of the upcoming five years, since the productivity factor would remain in effect during the term of the proposed price cap regardless

of actual changes in productivity (DOER Brief at 28). DOER asserts that, although the Company maintains that it relied on the formula established in NYNEX, Boston Gas's productivity offset formula contains factors which distinguish the Company's proposed formula from that approved in NYNEX (id.).

First, DOER maintains that NYNEX utilized TFP data from 19 telecommunications industry productivity growth studies, covering a 65-year period (id., citing NYNEX at 143). In contrast, DOER points out that the Company reviewed data over a ten-year span derived from only one study (id. at 29). Second, DOER points out that NYNEX's productivity factor is based on a national TFP, in contrast to Boston Gas's proposed regional TFP (id. at 29-30, citing NYNEX at 163).

DOER claims that the Company has failed to justify its use of a negative gas utility productivity factor based on Northeast gas industries, and has failed to demonstrate that its use is appropriate on a going-forward basis (id. at 35; DOER Reply Brief at 7). DOER acknowledges that while the Company's witnesses have presented data to support the Company's claim that the level of distribution costs is higher for gas utilities in the Northeast, the Company has failed to provide any documentation of the rate of change of these costs, which DOER maintains is the component captured in the productivity offset (DOER Brief at 32). DOER further claims that the incorporation of a negative productivity factor throughout the term of the price cap plan assumes that costs will continue to increase systematically in the Northeast region, an outcome which is contrary to the goals and purpose of price cap regulation (id.). DOER also argues that the Company should not rely solely on number of customers as the measure of growth in the Company's productivity analysis (id. at 34-35). DOER contends that because the proposed price cap adjustments would be based

on throughput, productivity also should be measured on a throughput basis (id. at 34). DOER notes that in 1995, Dr. Lowry performed a TFP analysis for another LDC that relied on throughput rather than number of customers (id., citing Exh. DOER-53, App. D at 64). For the aforementioned reasons, DOER recommends that the Department adjust the Company's TFP measure to include Dr. Lowry's national TFP factor and input price differential (id. at 36).

DOER asserts that based on the Department's findings in NYNEX, it is appropriate in the instant case to incorporate a 0.5 percent consumer dividend factor, as long as earnings sharing and other adjustments to the productivity factor are adopted (id.). Regarding accumulated inefficiencies, DOER maintains that the Company's productivity offset should incorporate an adjustment for accumulated inefficiencies (id. at 37). DOER suggests that the Company has disregarded the fact that an "average industry performer" subject to cost of service regulation likely has accumulated inefficiencies (id.). Further, DOER contends that the Company has overlooked the testimony of its own witnesses stating that the proposed "cast-off" rates do not incorporate all of the gains related to the QUEST initiative (id. at 38, citing Tr. 3, at 70-71; Tr. 16, at 84-85). Therefore, DOER recommends that rather than attempt to quantify all of the benefits related to the Company's QUEST initiative and other "unforeseen efficiencies that will occur under PBR on a going forward basis," an accumulated inefficiencies adjustment should be incorporated into the Company's productivity offset to flow these savings to ratepayers (id. at 38).

Based on its proposed adjustments to the Company's productivity offset, DOER recommends a 1.6 percent productivity offset [(0.4-0.3) - (3.1-3.6) + (0.5) + (0.5)] (id. at 39).

c. MOC

MOC argues that the Company has failed to demonstrate that the proposed productivity offset would incorporate greater levels of productivity than realized under cost of service regulation (MOC Brief at 15). MOC emphasizes that, but for the consumer dividend of 0.5 percent, the Company's proposed productivity factor would have been a negative figure (id. at 9). MOC maintains that even the consumer dividend does not result in any material benefit to the Company's ratepayers, since under cost of service regulation, the process of regulatory lag would provide financial benefits at least equal to the 0.5 percent consumer dividend (id. at 10, citing Tr. 16, at 140-141). Therefore, MOC argues that the Company's proposed price cap plan should be rejected (id. at 3).

d. AIM

AIM contends that a national TFP is appropriate for Boston Gas, because Massachusetts's employers compete on a national and international level (AIM Reply Brief at 3).

e. ComGas

ComGas disputes the proposition that there are accumulated inefficiencies embedded in utility rates, and argues that incorporating an accumulated inefficiencies component in the productivity offset is inappropriate (ComGas Brief at 21). As reasons therefor, ComGas argues that an accumulated inefficiencies component (1) is an arbitrary and unfair measure of actual productivity, and (2) double counts any adjustments the Department authorizes to starting point rates (id.). ComGas concludes that authorizing an accumulated inefficiencies component could subject the Department's decision to legal challenge by affected utilities (id. at 21-22).

f. Essex

Essex argues that the Department should not adopt a national productivity index, since it does not reflect the material differences between LDCs in the northeast region and those in other parts of the country (Essex Reply Brief at 4). Essex points to factors such as the age of the system, and the composition of mains and services as factors which Essex contends distinguish the regional LDCs, and are a significant component of the cost profile of LDCs in the region (id.).

Essex maintains that the Attorney General's and DOER's proposed incorporation of an accumulated inefficiencies component represents an effort to penalize LDCs for inefficiencies which remain undocumented and speculative (id.). Essex asserts that failure to allow a utility to recover these costs would be confiscatory, and could result in legal challenge for lack of substantial evidence (id.).

g. The Company

The Company states that the Attorney General's argument that Dr. Lowry's analysis contains proprietary, unverifiable data, is unfounded, because the information is contained in publicly available uniform statistical reports and was made available to the parties (Company Brief at 45). In response to DOER's recommendations that the Department adopt a national productivity factor as opposed to a regional productivity factor, the Company makes the following arguments: (1) that DOER's argument discounts the record and ignores the physical and economic environment in which Boston Gas operates; (2) that DOER's witness concedes that "the Northeast region is a good proxy for prices for Boston Gas;" (3) that the Northeast has higher average wage rates and severe weather (resulting in higher maintenance costs) older distribution systems, more urbanization, and slower population growth, all of which increase

unit costs (id. at 46-47, citing Exhs. BGC-13, at 3; BGC-15; Tr. 18, at 12; Tr. 8, at 107); and (4) in comparison to NYNEX which includes a national factor, a regional total factor productivity would have been inappropriate for NYNEX, because of its service territory (id. at 48).

Boston Gas also maintains that the productivity factor is based on historic data and indicates an industry's historic productivity, while future performance and anticipated industry efficiency gains are properly reflected in the consumer dividend (id. at 47).

In response to the Attorney General's recommendation to include a volume related output index in the TFP calculation, the Company argues that Dr. Lowry rejected this approach because of: (1) insufficient data; (2) complexity; (3) instability; (4) inaccurate accounting issues; and (5) double counting of interstate level volumes (id. at 48-49, citing Tr. 7, at 116-119). Boston Gas argues that in their advocacy for a national TFP, DOER and the Attorney General recommend including a national input price differential, but provided no support for this position. Further, the Company points out that the input price differential would be updated when the company reviews its plan at the end of the term (id. at 50).

Regarding the consumer dividend, the Company claims that NYNEX's consumer dividend of one percent should not be applied to Boston Gas, because of the difference in future efficiency gains between the telecommunications and the LDC industries (id. at 51).

Regarding accumulated inefficiencies, Boston Gas maintains that an accumulated inefficiencies factor should not be included in its productivity offset, because it is an above average cost performer and has taken steps to increase the efficiency of its business (id. at 52, citing Exhs. BGC-12; BGC-15; Tr. 16, at 78-79). The Company urges the Department to reject both DOER's and the Attorney General's recommended accumulated inefficiencies

factors, because the record supports neither their calculations or the position that such a factor should be incorporated in the productivity offset (id. at 52-54).

3. Analysis and Findings

a. Introduction

As an initial matter, the Department addresses the issue of whether the proposed price cap plan should be rejected in whole, as advocated by the Attorney General and MOC. The Department rejects this recommendation. The Department has previously stated that a well-designed price cap plan should be consistent with the standard of review established in Incentive Ratemaking. May 1, 1996 Explanatory Statement in D.P.U. 96-100, at 71-76. While the Department has identified a number of concerns with the components and provisions included in the plan and shall direct the Company to modify those components and provisions of the proposed plan, we find that the Company's customers would be better served by modifications to the proposed plan rather than an outright rejection of the plan.

b. Inflation Index

In NYNEX at 141, the Department found that the GDP-PI is (1) the most accurate and relevant measure of the output price changes for the bundle of goods and services whose TFP growth is measured by the Bureau of Labor Statistics, (2) readily available, (3) more stable than other inflation measures, and (4) maintained on a timely basis. In the instant proceeding, no party disputes that the GDP-PI is an appropriate measure for inflation in a price cap formula. Accordingly, the Department approves the use of the GDP-PI in the Company's price cap formula.

c. Productivity Offset

i. Introduction

There are four components that could be included in the calculation of the productivity offset: (1) a productivity growth index, which is intended to reflect the average annual growth in productivity, during a specified time period, for the companies that comprise a regulated industry; (2) an input price growth index, which is intended to reflect the average annual growth in input prices, during a specified time period, for the companies that comprise a regulated industry; (3) a consumer dividend factor, which is intended to reflect expected future gains in productivity for the companies that comprise a regulated industry, due to the move from cost of service to performance-based regulation; and (4) an accumulated inefficiencies factor, which is intended to reflect the inefficiencies built into the base rates for companies that comprise a regulated industry because of the historic use of cost of service regulation. See NYNEX at 160-168.

ii. Productivity and Input Price Growth Indices

The productivity and input price growth indices are intended to reflect the average annual growth in productivity and input prices, during a specified time period, for the companies that comprise a regulated industry. Considered jointly, these indices should reflect the average annual increase in per-unit costs, during the specified period, for the regulated companies.[122] For a particular company, the indices serve as proxies for the growth in per-unit costs that the company should have experienced during the specified period, if it were

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[122] For companies operating in a competitive market, the trend in per unit costs should be equal to the trend in output prices (Exh. BGC-10, at 4-5). Therefore, the difference between an industry's per unit costs and the per unit costs of the U.S. economy should be equal to the difference between the industry's output prices and price inflation for the overall economy.

an average-performing company. A company that achieved lower-than-average growth in per-unit costs during this period would be rewarded under a price cap, i.e., would have the opportunity to earn additional profits. Conversely, a company whose growth in per-unit costs exceeded the average might realize lower-than-anticipated profits.

In the instant proceeding, the Department must decide whether, for Boston Gas, the historic productivity and input price growth indices should be based on the historic productivity and input price growth indices of regional or nationwide LDCs. The Department addresses input price growth first.

The Company's productivity study found that there was a statistically significant difference between the historic growth of input prices for regional LDCs and the historic growth of input prices for nationwide LDCs. The results of the productivity study indicate that, between 1984 and 1994, the period covered by the study, regional LDCs experienced an annual input price growth rate of 3.7 percent, while for nationwide LDCs, input prices grew at an annual rate of 3.1 percent. Thus, even if the historic productivity growth levels of regional LDCs were equal to the growth levels of nationwide LDCs, the difference in input price growth would have resulted in higher per-unit costs, over the specified period, for the regional LDCs. The Department finds that, because the price cap formula is intended to reflect Boston Gas's historic per-unit costs, it is appropriate to use the regional LDC input price growth reported by the productivity study, or 3.7 percent, in the price cap formula.

The use of regional LDC input price growth data does not require the corresponding use of regional LDC productivity growth data. This is because, as stated above, the productivity index is intended to capture the trend in an industry's unit costs that is not due to input price increases. However, based on the results of the Berndt cost study, which found

that, holding all other variables constant (e.g., the cost of capital and labor), "transportation costs in New England are higher than in the rest of the nation," the Department finds that the use of productivity growth for regional LDCs is appropriate for Boston Gas.

The Company's productivity study reported historic productivity growth equal to -0.1 percent for regional LDCs. The Department finds that the study understated productivity growth for both the regional and nationwide LDCs because it did not account for increased gas delivery throughput in calculating the output quantity index.[123] The output quantity index was intended to reflect the growth in gas delivery output of LDCs. Because of its reliance on number of customers as the sole indicator of LDC output growth, the productivity study would not have captured productivity gains that might have resulted from increases in throughput-per-customer during the years covered by the study.[124] As the Company's witness, Dr. Lowry, stated in a report issued in January 1995,[125] "Lower productivity estimates might be expected when output indexes are based on the number of customers. Deliveries per customer rose for several output categories during the 1984-1993 period. Consequently, an output index based solely on customer numbers may tend to understate output growth" (Tr. 7, at 120).

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[123] As stated above, the productivity index was calculated as the ratio of an output quantity index to an input quantity index.

[124] In effect, the study's productivity growth results are based on the assumption that gas delivery throughput-per-customer remained constant during the period covered by the study.

[125] The report, titled "Productivity Trends of U.S. Gas Distributors," was prepared for Southern California Gas as part of that company's development of a rate indexing plan for its gas delivery services. See Exh. DOER-46.

The Company's cost-performance studies provide further evidence that increases in gas delivery throughput during the period covered by the productivity study would have resulted in higher levels of productivity growth. The Berndt cost study found that "increases in the number of customers have a much greater impact on transportation costs than do increases in throughput" (Exh. BGC-15, at 17),[126] while the Lowry study found that the gas delivery costs of LDCs are much more sensitive to change in the number of customers than to changes in gas throughput or sendout (Exh. BGC-12, at 13).[127] The findings of the cost-performance studies demonstrate that, to the extent that regional and nationwide LDCs experienced increases in throughput-per-customer from 1984 through 1994, the result would have been increased productivity growth levels that would not have been reflected in the productivity study.

The record in this proceeding supports the conclusion that throughput-per-customer increased during this period. First, in a presentation to financial and rating agencies, the Company stated that "Number of customers is not indicative of our growth because, in the residential sector, growth results primarily form increasing customers's use of gas. A more appropriate measure is total throughput or use per customer" (Exh. AG-5). Second, during the period included in the productivity study, 1984-1994, gas marketers significantly increased

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126 The Berndt cost study reported that a 1.0 percent increase in total customers would result in a 0.83 increase in total gas delivery costs, while a 1.0 percent increase in total throughput would result in only a 0.14 increase in total gas delivery costs (Exh. BGC-15, at 16).

127 The Lowry cost study reported that a 1.0 percent increase in number of customers would result in a 0.457 increase in total gas delivery costs, while a 1.0 percent increase in firm volume would result in only a 0.049 increase in total gas delivery costs (the firm volume result was not statistically significant) (Exh. BGC-15, at 12-13).

their activities due to the unbundling of services in the gas industry. This increased activity of marketers was targeted at the Company's most price-elastic customers, large C&I customers (Tr. 18, at 30-38). As such, it is likely that, for these customers, throughput-per-customer increased during this period.

Dr. Lowry testified that the decision to rely solely on number of customers in the calculation of the output quantity index was an attempt to balance the need to produce accurate productivity growth results with the desire to simplify the calculation of productivity growth (Tr. 16, at 33-34). Dr. Lowry testified that, because customer growth is the most important cost driver in the gas distribution industry, reliance on number of customers in the calculation of the output quantity index should produce reasonably accurate productivity growth levels while avoiding various problems associated with gas delivery throughput (Exh. BGC-10, at 12; Tr. 7, at 115-16).[128]

In NYNEX at 160-161, the Department explained why the determination of the productivity offset is critical for a price cap plan:

> Determining the appropriate productivity offset is the most important and difficult part of creating a well-designed price cap plan -- important because it determines the level of aggregate rate change for the firm, and difficult because it requires regulators to predict the average annual TFP and input price growth of the industry over the term of the price cap plan."

In the instant proceeding, the Department finds that the added complexity that would result from including gas delivery throughput in the calculation of the output quantity index is

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128 Dr. Lowry testified that including gas delivery throughput would be problematic because: (1) throughput is sensitive to short-term demand factors, such as weather; (2) it might introduce measurement bias due to double-counting at the federal pipeline level; and (3) it might introduce aggregation bias due to the growth of independent power producers served from low-cost, high pressure spurs (Tr. 7, at 115-119; Tr. 16, at 33).

outweighed by the benefits of increased accuracy that such inclusion would provide. Based on the record evidence, the Department finds that throughput-per-customer did increase during the period 1984 through 1994, and that this increase produced greater productivity levels that were not reflected in the results of the Company's productivity study. As such, the Department finds that reliance on number of customers as the sole factor in calculating the output quantity index resulted in a downward bias in the productivity growth levels produced by the productivity study.

Based on the above analysis, the Department finds that the productivity index produced by the productivity study does not appropriately reflect the historic productivity growth of regional LDCs. Therefore, the Department rejects the study's regional LDCs productivity growth index, -0.1 percent, for use in Boston Gas's price cap formula. Alternatively, the record justifies adoption of either the 0.3 percent productivity growth for the U.S. economy or the 0.4 percent productivity growth from 1984 through 1994 produced by the productivity study for nationwide LDCs. The Department finds that the productivity growth for nationwide LDCs reported by the productivity study is the more reasonable proxy for regional LDC productivity growth.[129] Therefore, the Department finds that the productivity growth index of the price cap formula should be equal to 0.4 percent.

iii. Consumer Dividend

The Department stated its rationale for including a consumer dividend factor in the productivity offset of a price cap formula in NYNEX at 165-166.

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129 For the reasons discussed above, the Department considers that the historic productivity growth for nationwide LDCs produced by the productivity study, 0.4 percent, understates the actual historic productivity growth for nationwide LDCs during the years 1984 through 1994.

> Because well-designed price cap regulation is superior to rate of return regulation in promoting economic efficiency, the average annual productivity of the industry should be higher if the firms in the industry are regulated under a price cap rather than ROR. Therefore, if the productivity factor is based on the historic experience of the industry, the productivity offset for the future should be higher to compensate for this expected productivity gain.

The Department found that the consumer dividend factor should be equal to one percent to account for the expected increase in productivity, i.e., NYNEX should be at least one percent more productive than the average firm in the telecommunications industry has been over the past 65 years, in order to maintain its earnings at a constant level. Id. at 166. Thus, the consumer dividend factor serves as a "future" productivity factor because it is intended to reflect expected future gains in productivity due to the move from cost-of-service regulation to performance-based regulation. Predicting the future productivity growth for Boston Gas is difficult at the present time because so little information currently exists regarding the efficiency improvements that should result as regulated gas utilities move from cost-of-service to performance-based regulation.

In the instant proceeding, the Company proposed a 0.5 percent consumer dividend, and argued that, because of the fundamental differences between the telecommunications and gas distribution industries, it would be inappropriate to apply the expected productivity gains of the telecommunications industry to the gas distribution industry. The Department recognizes that the potential for efficiency improvements is greater in the telecommunications industry than in the gas distribution industry due to rapid technological advances occurring in the telecommunications industry. However, as discussed below, the Department finds that this factor is balanced by two other considerations that should result in increased productivity growth for Boston Gas during the term of the price cap plan.

First, there are anticipated QUEST productivity gains that were not captured during the test year or post-test year periods. The Company testified that it expects to reap future benefits from implementation of the QUEST program, but that those benefits currently are impossible to quantify (Exh. BGC-38, at 28-29; Tr. 1, at 39; Tr. 3, at 71). The Department finds that, in order for the Company's ratepayers to capture some of these future benefits, it is necessary to reflect the benefits in the consumer dividend factor of the productivity offset. Second, the Department anticipates that the unbundling of services in the gas industry, and the corresponding increased activities of gas marketers, should result in increased gas delivery throughput (Tr. 7, at 121-122). The Department finds that, in order for the Company's ratepayers to capture some of the benefits associated with increased throughput, it is necessary to reflect this increase in the consumer dividend factor of the productivity offset.

Therefore, the Department rejects the Company's proposed 0.5 percent consumer dividend factor. Instead, the Department finds that an appropriate and reasonable adjustment to account for expected productivity gains due to movement away from cost-of-service regulation is 1.0 percent. Accordingly, the Department finds that Boston Gas's price cap formula shall include a consumer dividend factor equal to 1.0 percent.

iv. Accumulated Inefficiencies

The Department stated its rationale for including an accumulated inefficiencies factor in the productivity offset of a price cap formula in NYNEX at 166-167.

> If the telecommunications industry has been operating less efficiently during the long-term period that is the foundation of the productivity offset than it would have under price cap regulation (a notion that must be acknowledged in order to accept price cap regulation as superior to rate-of-return regulation in maximizing economic efficiency), then there must be accumulated inefficiencies that should be accounted for in the first term of a price cap plan .... [W]e find our acceptance of the underlying rationale for approving price cap regulation, i.e., that the average firm under price cap regulation will be more efficient than

> the average firm under ROR regulation, requires us also to find that there are accumulated inefficiencies in the Company's current operations that the Department was unable to discover in its earnings review and would be unable to discover in a traditional rate case.

The Department finds that this rationale applies equally to companies that comprise the regulated gas distribution industry. The Department rejects Boston Gas's assertion that, because its cost-performance studies indicate that the Company is an average cost-performer in the gas distribution industry, it is unnecessary and inappropriate to include an accumulated inefficiencies factor in the productivity offset of its price cap formula. A more appropriate interpretation of the results of the studies is that the accumulated inefficiencies included in the Company's base rates are similar in magnitude to the accumulated inefficiencies included in the base rates of other average-performing gas distribution companies. In order to accept the Company's assertion regarding accumulated inefficiencies, one would have to conclude that the average-performing gas distribution company did not have accumulated inefficiencies. The Department rejected that conclusion in NYNEX. Therefore, the Department finds that the revenue requirement reflected in the Company's cast-off rates includes accumulated inefficiencies that must be taken into consideration in the price cap formula. In the absence of such a provision, the Company's ratepayers would receive none of the benefits associated with eliminating these inefficiencies.

As discussed above, there is little information regarding the efficiency improvements that should result as regulated companies move from cost-of-service regulation to performance-based regulation. The record in this proceeding provides a basis for adoption of either the 1.0 percent accumulated inefficiencies factor approved by the Department in NYNEX, or the Attorney General's recommended value of 2.5 percent. The Department rejects the Attorney General's recommended value of 2.5 percent because it is based on the

difference between the productivity growth levels of regional LDCs and those of nationwide LDCs. This approach to calculating the accumulated inefficiencies factor would contradict the Department's finding that Boston Gas historic performance should be judged in comparison to regional, and not nationwide, LDCs.

Both the telecommunications and gas distribution industries have operated under cost of service regulation for over 100 years. The Department finds that the finding in NYNEX regarding accumulated inefficiencies in the telecommunications industry is an appropriate proxy for the level of accumulated inefficiencies in the gas distribution industry. Therefore, the Department finds that, at least during the initial five-year term of the price cap plan, Boston Gas's price cap formula should include an accumulated inefficiencies factor equal to 1.0 percent.

v. Summary

Based on the findings stated above, the Department orders the Company to recalculate the productivity offset in the following manner. First, the Company is directed to use a value of 3.7 percent for the input price growth index. Second, the Company shall use a value of 0.4 percent for the productivity growth index. Third, the Company is directed to include a consumer dividend factor equal to 1.0 percent. Finally, the Company is directed to include a 1.0 percent accumulated inefficiencies factor. This results in an overall productivity offset equal to 2.0 percent.[130]

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130 This result is calculated as:

$$X = (TFP_{(NEgas)} - TFP_{(US)}) - (IP_{(NEgas)} - IP_{(US)}) + CD + \text{Accumulated Inefficiencies}$$

$$X = (0.4 - 0.3) - (3.7 - 3.6) + 1.0 + 1.0 = 2.0$$

C. Exogenous Cost Factor

1. The Company's Proposal

The Company's proposal would allow it to recover exogenous costs, which it defines as positive or negative cost changes that are beyond the Company's control and not reflected in the GDP-PI (Exh. BGC-3, at 19). The Company stated that this would include, but would not be limited to, cost changes resulting from:

- changes in generally accepted accounting principles affecting the gas utility industry;
- changes in tax laws affecting the gas industry;
- regulatory, judicial or legislative changes affecting the gas industry;
- regulatory or governmental mandates affecting the Company;
- mandated investments for unreimbursed public works projects; and
- pipeline bypass by customers individually contributing annual transportation revenues exceeding $2 million.

(id.).

The Company proposed an exogenous cost threshold of $500,000, and stated that this level is consistent with the threshold approved by the Department in NYNEX (id. at 20). Under its proposal, the Company would absorb the first $500,000 of exogenous costs in the year that the cost was incurred (id.). Exogenous cost impacts above the $500,000 threshold would be deferred with interest and reflected in rates for the following year only.[131] Ongoing

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[131] The formula for converting exogenous costs expressed in dollars into an exogenous factor expressed as a percentage is:

$$Z_{(t)} = (C_t - (C_{(t-1)} (1+I_t-X))) / R_{(t-1)}, \text{ where}$$

C_t is the exogenous cost in year t (less the $500,000 threshold);
$C_{(t-1)}$ is the exogenous cost in year t-1 (less the $500,000 threshold);
I_t is the inflation index for year t;
X is the productivity offset;
$R_{(t-1)}$ is the Company's normalized revenue in year (t-1).

(Exh. BGC-5, at 4).

exogenous cost changes would be reflected in the Company's rates for the duration of the plan (id.). The Company proposed that exogenous costs be considered cumulatively when determining whether the $500,000 threshold was exceeded. That is, if the sum of all exogenous costs in one year exceeded $500,000, then the Company would be entitled to recovery of those costs that exceeded the threshold (Tr. 3, at 57, 82).

2. Positions of the Parties

a. The Attorney General

The Attorney General argues that the Department should restrict any exogenous cost adjustment to include only those costs of the Company's operation that are (1) genuinely out of the Company's control, (2) not included in the revenues or the price cap inflation component of the price cap formula, and (3) significant in amount relative to the Company's total costs (Attorney General Brief at 25). According to the Attorney General, the Company seeks to recover not only those exogenous changes it specifically requested, but also any possible change whether unforeseen or not (id.,citing Exh. BGC-3, at 19). Therefore, the Attorney General alleges that the Company's definition of exogenous costs does not provide a reasonable framework for a price cap plan (id. at 25).

The Attorney General maintains that Boston Gas's proposed exogenous cost changes have several flaws and recommends several modifications. First, the Attorney General proposes that the Company's reference to "the gas industry" should be changed to "the regulated natural gas local distribution industry" (id. at 26). Second, the Attorney General proposes that exogenous costs should include only those costs associated with normal annually recurring expenses, and not mandated investments for unreimbursed public works projects, since similar recurring costs associated with these projects are already recovered through the

cost of service (id.). Third, the Attorney General proposes that exogenous costs should not include changes in revenues associated with the loss of a customer, since customer retention is within the control of the Company (id.). Finally, the Attorney General proposes that regulatory or governmental mandates affecting costs not be treated as an exogenous cost, because it is within the Company's control to intervene in order to reduce or eliminate those costs (id.).

In examining the definition of exogenous costs adopted in NYNEX, the Attorney General recommends putting a similar definition in place for Boston Gas:

> Exogenous costs should be defined as known and measurable positive or negative cost changes actually beyond the Company's control and not reflected in the GDP-PI resulting from:
>
> - Changes in tax laws that uniquely affect the regulated natural gas local distribution industry;
> - accounting changes unique to the regulated natural gas local distribution industry; and
> - regulatory, jurisdictional, or legislative changes uniquely affecting the regulated natural gas local distribution industry.

Id. at 27.

Finally, the Attorney General recommends two modifications relative to the application of exogenous costs. First, he suggests that the exogenous costs adjustment be prospective in nature, to prevent the Company from recovering any costs incurred prior to the year in which the new rates resulting from the annual price cap adjustment are implemented (Attorney General Brief at 28). Second, the Attorney General advocates setting a threshold dollar amount on individual exogenous costs and not on cumulative exogenous costs (Attorney General Reply Brief at 10-11).

b. DOER

DOER recognizes that under Boston Gas's proposal, the Company is at liberty to propose categories of exogenous costs in any price cap filing and, therefore, suggests that the Department define as narrowly as possible those exogenous costs it deems appropriate in a price cap filing (DOER Brief at 40). Regarding the exogenous factors proposed by the Company, DOER maintains that Boston Gas's proposed factors are overly broad, and include factors that are within the Company's control and thus should be eliminated (id. at 39).

DOER recommends that the Department adopt the following modifications to Boston Gas's proposed exogenous factors. First, where the Company refers to changes affecting "the gas industry," DOER proposes that the language should be changed to changes "uniquely affecting the gas utility industry" (id. at 41). Second, DOER argues that exogenous costs should not include regulatory or governmental mandates that affect costs, since this category appears to duplicate other proposed categories (id.). Third, DOER asserts that the Department must reject Boston Gas's inclusion of unreimbursed public works expenses as an exogenous cost (id.). DOER notes that the Company has incurred no such costs to date (id., citing Tr. 3, at 81). DOER maintains that if the Department were to determine that such expenses are exogenous, this provision would dissipate Boston Gas's incentive to take affirmative steps to recover these costs (id. at 41-42).

Fourth, DOER argues that changes in revenue related to the loss of a single large customer must not be construed as an exogenous cost (id. at 42). DOER asserts that because the matter of negotiation of special contracts is clearly within the control of the Company, approval of such an exogenous factor would function in a one-sided manner only, to the detriment of the ratepayers (id. at 41). Further, DOER asserts that incorporation of such an

exogenous cost belies Boston Gas's assertion that the Company's shareholders bear the risk for losses of throughput (id. at 42, citing Exh. BGC-3, at 47-48). Fifth, DOER maintains that the Company must demonstrate that any claimed exogenous cost is not otherwise reflected in the GDP-PI (id. at 42). Finally, DOER argues that the Company's proposal to accumulate exogenous costs is inconsistent with both NYNEX and with the concept of exogenous costs as being those costs which have a material impact on a company's operating revenues (id. at 43, citing NYNEX at 173). Accordingly, DOER urges the Department to require the Company to demonstrate that any proposed individual exogenous expense satisfies the $500,000 threshold (id. at 43).

c. AIM

AIM asserts that the Company's definition of exogenous costs is too broad because it incorporates items that are within the Company's control and allows for accumulation of individual factors to meet the materiality threshold (AIM Brief at 12).

d. ComGas

ComGas argues that the Department should approve adjustments for exogenous costs that incorporate routine costs associated with distribution-related investments and other investments. ComGas contends that gas distribution companies periodically incur these "lump" costs to ensure reliable service for its customers, and these costs may not correspond to a long-term price cap formula (ComGas Brief at 22).

e. The Company

The Company disputes most of the Attorney General's and DOER's criticisms of and recommended modifications to the definition of exogenous costs. The Company concurs that items already reflected in GDP-PI, such as general taxes and broad-based government

regulations, should be excluded from consideration as exogenous (Company Brief at 57, citing Tr. 7, at 122, 127, NYNEX at 172).

In response to the Attorney General's and the DOER's proposals to narrow the scope of the affected industry, the Company states that to the extent changes in tax laws, and regulatory, judicial, or legislative changes affect both the gas and electric industry, their modifications would preclude consideration of these categories as exogenous. Therefore, the Company proposes that the term "gas utility industry" be replaced with "energy utility industry" (id. at 56). In response to DOER's argument that mandated investments for unreimbursed public works projects are inconsistent with NYNEX, Boston Gas maintains that such cost changes are beyond the Company's control and not reflected in the GDP-PI. Therefore, the Company asserts that the inclusion of such costs is consistent with NYNEX (id. at 56, citing NYNEX at 172). Boston Gas also disputes the Attorney General's argument that these costs already are included in the cost of service (id. at 57, citing Tr. 3, at 81). In response to the Attorney General's and DOER's argument that retaining customers is within the Company's control, Boston Gas points out that its witness testified that retaining a customer such as BECo is outside the Company's control, and that a replacement customer is unlikely (id. at 57, citing Tr. 3, at 85). In addition, the Company notes that the exogenous provision would be triggered only if BECo selects an economic bypass option at the expiration of its contract in 2000 (id. at 57).

3. Analysis and Findings

In this section, the Department addresses two issues associated with Boston Gas's proposed treatment of exogenous costs: (1) the proposed list of exogenous cost categories;

and (2) the proposal that exogenous costs be considered on a cumulative basis when determining whether the $500,000 threshold has been exceeded.

In Incentive Regulation at 62, the Department recognized there may be exogenous costs that are beyond the control of a company, e.g., changes relating to income tax rates, governmental accounting standards boards, and regulatory, judicial, or legislative action. The Department stated that it may be appropriate for a PBR proposal to allow for the recovery of these exogenous costs, but emphasized that proposals that focus excessively on cost recovery issues may miss the point behind incentive regulation. The Department stated that, if a PBR proposal includes a provision for exogenous cost recovery, the proponent of such recovery must present evidence on (1) the nature of any exogenous costs for which specific rate treatment is sought, and (2) the reason why these costs should be treated in a different manner from any other utility costs that are subject to the incentive mechanism.

In NYNEX at 172-173, the Department found that exogenous costs should be defined as positive or negative cost changes actually beyond the Company's control and not reflected in the GDP-PI, including, but not limited to, cost changes resulting from:

- changes in tax laws that uniquely affect the telecommunications industry;
- accounting changes unique to the telecommunications industry;
- regulatory, judicial or legislative changes uniquely affecting the telecommunications industry; and
- mandated jurisdictional separation changes.

The Department stated that the proponent of an exogenous cost adjustment will bear the burden of proof of demonstrating (1) the propriety of the exogenous cost, and (2) that the proposed exogenous cost change has not been reflected in the GDP-PI. NYNEX at 173.

In the instant proceeding, the Company has adopted the general definition of exogenous costs applied in NYNEX, but has proposed modifications to, and expanded upon,

the list of exogenous costs approved in NYNEX. Under the Company's proposal, costs related to changes in tax laws, accounting principles, and regulatory, judicial or legislative action would not have to affect the gas industry "uniquely" in order to qualify as exogenous. Instead, these changes would only have to affect the gas industry. The Department finds that, because the price cap will apply only to the Company's distribution services, it is appropriate to refer to the local gas distribution industry, rather than the gas industry. In addition, the Department finds that it would be inappropriate to eliminate the requirement that exogenous costs uniquely affect the local gas distribution industry because cost changes that are not unique to the gas distribution industry may be reflected, to some degree, in the GDP-PI (Tr. 7, at 127).

The Company has included three additional items in its exogenous cost list, associated with cost changes from (1) regulatory or governmental mandates, (2) mandated investments for unreimbursed public works projects, and (3) pipeline bypass by customers individually contributing annual transportation revenues exceeding $2 million. The Department finds that including cost changes resulting from regulatory or governmental mandates would be redundant in that these costs are adequately covered in the category addressing regulatory, judicial or legislative changes. In addition, the Department finds that the Company has not sufficiently demonstrated that cost changes resulting from (1) mandated investments for unreimbursed public works projects, or (2) pipeline bypass by customers individually contributing annual transportation revenues exceeding $2 million qualify as exogenous costs.[132] The Department also finds that the instant proceeding is not the appropriate forum for making

132 In particular, the Department is not convinced that pipeline bypass by customers individually contributing annual transportation revenues exceeding $2 million is beyond the control of the Company.

this demonstration. The Department may determine that cost changes resulting from these events qualify for recovery as exogenous costs, but proponents must demonstrate the appropriateness of such recovery at the time of the Company's annual price cap compliance filings.[133]

The Department finds that, except for the item, "mandated jurisdictional separation changes," the list of exogenous costs approved in NYNEX is not unique to the telecommunications industry and can be reasonably applied to the Boston Gas proposal, with the obvious substitution of the term "gas distribution industry" for "telecommunications industry." Therefore, the Department finds that, for the purposes of the Boston Gas price cap plan, exogenous costs shall be defined as positive or negative cost changes actually beyond the Company's control and not reflected in the GDP-PI, including, but not limited to, cost changes resulting from:

- changes in tax laws that uniquely affect the local gas distribution industry;
- accounting changes unique to the local gas distribution industry; and
- regulatory, judicial or legislative changes uniquely affecting the local gas distribution industry.

As stated above, proponents of exogenous cost recovery will bear the burden of demonstrating that the costs were (1) beyond the company's control, and (2) not reflected in the GDP-PI.

Finally, the Department rejects the Company's proposal that exogenous costs in a particular year be considered on a cumulative basis when determining whether the $500,000

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133 The Department notes that the list of exogenous cost categories approved in this proceeding is not meant to be inclusive. At the time of the annual price cap compliance filings, the Company and other parties will have the opportunity to demonstrate that costs not included in the approved list should be treated as exogenous costs, i.e., that the costs were beyond the company's control and were not reflected in the GDP-PI.

threshold was exceeded. In NYNEX at 173, the Department stated that "there should be a threshold for qualification as an exogenous cost in order to avoid regulatory battles about minimal dollars." The Department's intent was that any individual exogenous cost must exceed the threshold in order to qualify for recovery. In the instant proceeding, the Department finds that this precedent is appropriately applied to Boston Gas's price cap plan. The Department finds that, in addition to creating opportunities for "regulatory battles about minimal dollars," using a cumulative threshold would be inconsistent with the Department's directive in Incentive Regulation that PBR proposals not focus excessively on cost recovery issues. Therefore, the Department finds that the impact for individual exogenous costs must exceed $500,000 in a particular year in order for the Company or other parties to request recovery.

D. Service Quality Index

1. The Company's Proposal

The Company proposed a service quality index ("SQI") that would provide a penalty of up to $1 million if it fails to maintain specified levels of customer service quality (Exh. BGC-13, at 23). The Company based its proposed SQI on three customer service categories: (1) safety; (2) service; and (3) billing (Exh. BGC-16, at 23). Boston Gas proposed the following performance measures, benchmarks, and weights the Company would accord each category for its SQI:

Customer Service Category	Performance Measure	Benchmark/ Target Value	Weights
Safety	Class I and II odor calls responded to in one hour or less	95%	45%
	Three year running average for lost time accidents	Less than the three year average	
Service	Telephone Service Factor - Calls answered within 40 seconds	90% - Emergency 80% - Service/ Billing	30%
	Service appointments met on the same day requested	95%	
Billing	Actual on-cycle meter reads	92%	25%

Company Brief at 65.[134]

The Company described the safety category as the most important aspect of its operations (Exh. BGC-16, at 26). As noted above, Boston Gas chose two performance measures of safety: (1) Class I and Class II odor calls; and (2) lost time accidents (id.; Company Brief at 65, App. B). The Company defined Class I calls as those which relate to a strong odor of gas throughout a household or outdoor area, or a severe odor from a particular area; Class II calls involve an occasional or slight odor at an appliance (Exh. BGC-16, at 26). Boston Gas stated that its objective is to respond to all odor calls within one hour. Boston Gas asserted that it would be impossible to meet 100 percent of its objective and instead

134 On brief, the Company revised its original proposal to include lost time accidents and telephone service factor as two additional performance measures (Exh. BGC-16, at 23; Company Brief at 65).

proposed a benchmark of 95 percent, i.e., the Company would be penalized if less than 95 percent of all odor calls were responded to in one hour (id. at 27; Exh. BGC-24).

The Company proposed to measure its lost time accidents by comparing its most recent three-year running annual average incidence rate for lost time accidents to the most recent three-year running average for lost time accidents for Standard Industrial Classification, Code 4924 Natural Gas Distribution as reported by the National Safety Council's annual report entitled Work Injury and Illness Rates (Company Brief at App. B). The Company would be penalized if its number of fatalities, illnesses or injury exceeded the natural gas distribution industry average (id. at 65).

Regarding its service SQI, Boston Gas stated that in today's marketplace, it is vitally important to make service calls as scheduled (Exh. BGC-16, at 28). The Company chose two performance measures for service: (1) percentage of service appointments met on the same day requested; and (2) telephone service factor ("TSF") -- telephone calls answered within 40 seconds (id.; Company Brief at 65). Boston Gas maintained that, ideally, the Company would keep all service appointments as scheduled; however, exigencies such as responding to odor reports result in the Company rescheduling some appointments. Therefore, the Company proposed a benchmark of 95 percent, i.e., the Company would be penalized if less than 95 percent of service appointments were met on the same day requested (Exhs. BGC-16, at 28; BGC-25). The Company's proposed benchmarks for the TSF measure would require the Company to provide a human contact for 90 percent of all emergency calls and 80 percent

of all billing and service calls within 40 seconds from the time the Company's Teloquent[135] system picks up the call (Company Brief at 61, App. A).

Regarding its billing SQI, the Company asserted that estimated bills have been one of the main sources of customer dissatisfaction (Exh. BGC-16, at 29). Therefore, Boston Gas chose a performance measure of the percentage of actual on-cycle meter reads (id.). The Company indicated that to date it has installed AMR devices on 81 percent of its system (Exh. BGC-16, at 29). The Company proposed a benchmark of 92 percent for actual on-cycle meter readings, i.e., the Company would be penalized if less than 92 percent of on-cycle meter readings were achieved (Exhs. BGC-16, at 29; BGC-26).

The Company stated that in calculating the SQI, it assigned a weight to each performance measure based on the results of a customer survey prepared by Opinion Dynamics Corporation ("ODC") (Exhs. BGC-16, at 24; BGC-22, at 50).[136] The SQI was calculated as:

$$I_t = \sum_{i=1}^{3} P_{it} * w_i$$

Where:

I_t	=	The value of the overall incentive index for year t;
P_{it}	=	The value of performance measure i in year t; and
w_i	=	The weight given to performance measure i.

(Exh. BGC-3, at 21).

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135 Teloquent is the Company's new telephone management system, which was installed in January 1996. It provides customers with a menu of options from which to select, including emergency, service, or billing inquiries (Exh. DPU-103).

136 ODC conducted 402 surveys, which asked Boston Gas's residential customers to rank on a scale from 1 to 3 the importance of the Company's originally proposed measures of responding to odor and service calls and reading meters on-cycle. Each measure's points were then tallied and its share of total points determined the proposed weight (Exh. BGC-22, at 1, 50).

In order to determine whether the Company would incur a penalty in a given year, the benchmark for each performance measure would be multiplied by the corresponding weight and then summed. The total value would then be compared to the actual performance in each measure multiplied by the weights and then summed (Exh. BGC-16, at 22). The Company would be penalized $200,000 for each one percent that the actual service quality index was below the benchmark index, up to a maximum penalty of $1,000,000 (id. at 23 (rev.)). The penalty would be determined by the following formula:

$$Pen_t = \frac{(T-I_t)*MP}{T-LV} \text{ ; if } LV \leq I_t \leq T$$

Where:

Pen_t	=	The dollar amount of penalty associated with the SQI;
T	=	Target/Benchmark Index = 94.3%;
I_t	=	Actual SQI in year t;
MP	=	Maximum Penalty = $1,000,000; and
LV	=	Lowest Value of the Index = 89.3%

(Exh. BGC-5, at 6 (rev.)).

Boston Gas proposed that the measurement period for SQI reporting purposes run from July 1 through June 30, with the annual reviews occurring in conjunction with the price cap compliance filings (Exh. BGC-16, at 25).

2. Positions of the Parties

a. Attorney General

The Attorney General criticizes the Company's proposed SQI for two reasons: (1) the benchmarks proposed by Boston Gas are too readily attainable; and (2) the penalty provision is too small. Regarding the odor call measure, the Attorney General argues that the Company employs a special leak response crew whose sole function is to respond to odor complaints and that the Company goal is to reduce the level of odorant by one-third, which

will reduce the number of odor calls by five to fifteen percent (Attorney General Brief at 10, citing Tr. 1, at 53; Tr. 7, at 160; Tr. 12, at 23, 47; RR-AG-1). The Attorney General claims that the Company already is addressing this issue and that ratepayers are funding this endeavor (id. at 10). Regarding the issue of benchmarking for on-cycle meter reads, the Attorney General points out that the Company has equipped between 80 to 85 percent of its meters with AMR devices and that it will install AMRs on virtually all Company meters by the beginning of 1997 (id. at 10, citing Tr. 12, at 86; RR-AG-1, at 124). Therefore, the Attorney General perceives the benchmark of 92 percent as too easy to achieve (Attorney General Brief at 10). The Attorney General recommends three modifications to the Company's proposed SQI.

First, the Attorney General contends that the Department should adopt a multi-point threshold for overall performance that would be either zero or negative if Boston Gas fails to meet either the overall service quality standards or fails in any month to reach the minimum levels of any three measures (id. at 9, citing NYNEX at 237-238). Second, the Attorney General maintains that the Department should implement a one-way annual penalty of one percent of the Company's revenues or $6 million (id. at 9). Third, the Attorney General recommends including additional measures with accompanying penalties such as: (1) Department complaint statistics measured against other LDCs's statistics; (2) telephone service-call response-time by a live operator for billing and service inquiries;[137] (3) cast iron replacement/relining as planned in the Company's pipe replacement program; (4) unaccounted-for gas loss of greater than one percent; (5) employee safety measured

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[137] Boston Gas revised its proposed SQI to include this measure (Company Brief at 65).

through lost employee hours and workforce efficiencies;[138] and (6) price performance measured against the national average gas transportation rates (Attorney General Brief at 10-11; Attorney General Reply Brief at 6 n.5).

b. DOER

DOER presents the following criticisms of the Company's proposed SQI: (1) the benchmarks proposed by Boston Gas are too readily attainable; (2) the field service measure does not fully measure Company performance or customer satisfaction; (3) the odor response measure does not adequately protect against the degradation of safety; (4) there should be additional service quality measures to avoid degradation of service; and (5) the penalty provision is too small and static (DOER Brief at 50-56).

First, DOER argues that the benchmark set for the actual meter readings measure is too low, stating that due to the implementation of AMR, in 1995 Boston Gas read 91.3 percent of meters on schedule (id. at 51, citing Exh. BGC-3 at 22 (rev.)). According to DOER, since the Company could easily meet and surpass this benchmark, DOER suggests that the Department incorporate an accuracy component to the standard (id. at 51).

Second, DOER claims that the field service measure of meeting scheduled appointments is not reflective of customer satisfaction, and recommends that the Department incorporate an additional component of a field service measure that would reflect customer assessment, such as satisfactory completion of the service requested (id. at 52).

Third, DOER points out that the Company proposed a 95 percent benchmark for responses to Class I and II odor calls within one hour, and that in 1995, the Company met that goal 92.7 percent of the time (id.). DOER maintains that Boston Gas has indicated that

138 Boston Gas revised its proposed SQI to include this measure (Company Brief at 65).

it has, and continues to, monitor its odorization level based on the recommendations of a QUEST report (id. at 52-53). Therefore, DOER asserts that it will be increasingly easier for the Company to meet its goal (id. at 53).

Fourth, DOER notes that the Company employs internal measures when assessing its quality of service, such as average response time for Class I and Class II odor calls, customer satisfaction surveys, number of telephone inquiries, the speed of answering phone calls, Department Consumer Division second referrals and cases, collection activity, frequency of meter failures, and monitoring of telephone contacts with customer service representatives (id. at 53-54, citing Exhs. DOER-47; DOER-52). Therefore, DOER recommends the inclusion of these measures in the SQI along with a measurement of the performance of Boston Gas compared to other LDCs in the Commonwealth and compliance with the Department's pipeline and safety engineering division requirements that includes employee accident rates (DOER Brief at 54).

Fifth, DOER points out that the Company may avoid incurring a penalty if it fails to meet one SQI goal, but outperforms in another goal (id. at 55, citing Tr. 4, at 21). Therefore, DOER recommends that Boston Gas be held to an adequate level of performance in each category. Further, DOER contends that a static $1 million penalty, as proposed by the Company, will be of diminishing magnitude to Boston Gas over the life of the plan. Therefore, DOER recommends instituting a penalty that escalates at the same pace as earnings in order to maintain the Company's level of incentive to retain service quality (Exh. DOER-70, at 25-26; DOER Brief at 56; DOER Reply Brief at 8).

In response to Boston Gas's revisions to the SQI to include telephone response time and employee safety, DOER questions whether the proposed corresponding goals and weights provide adequate incentives to the Company (DOER Reply Brief at 8).

c. The City of Boston

According to the City of Boston, the measures that Boston Gas includes in its proposed SQI are those in which the Company already has a strong profit incentive to excel (City of Boston Brief at 2). Conversely, the City of Boston asserts that the Company has the incentive to defer maintenance and improvement of its physical plant and its relations with "non-customers," such as cities and towns (id. at 3). Therefore, the City of Boston contends that the SQI should include the following measures to address this problem: (1) plant maintenance so that the Company would not have the incentive to repair a leak when it should replace the pipe; and (2) performance in relation to cities and towns, which would compare the number of repairs in a particular street over time to the cost of pipe replacement and the cost of road maintenance or reconstruction (id. at 3-4). According to the City of Boston, this would ensure that utilities coordinate their plant maintenance with local street maintenance (id. at 5). In addition, the City of Boston suggests that the Company provide cities and towns with its three-year cast iron replacement or abandonment schedule, as required by 220 C.M.R. § 113.05(c) (id. at 5-6).

d. The Company

Boston Gas disputes the parties's recommendations to incorporate the following additional measures in the SQI: (1) Department complaint statistics; (2) a cast iron main replacement measure; (3) an unaccounted-for-gas measure at one percent; (4) average response time for Class I and Class II odor calls; (5) customer satisfaction surveys;

(6) number of customer telephone inquiries and monitoring of telephone contacts; and (7) frequency of meter failures (Company Brief at 62, citing Attorney General Brief at 10-11; DOER Brief at 54; City of Boston Brief at 2-5). First, Boston Gas states that Department complaint statistics are not an appropriate measure for the SQI, because they are not conclusive and they involve only 0.5 percent of the Company's customers. Further, the Company asserts that its aggressive collection efforts result in customer complaints (Company Brief at 62).

Second, the Company claims that it is already committed to its cast iron main replacement program to maintain safety and reliability. Therefore, Boston Gas asserts that such a measure would be superfluous (id. at 63). Third, as a result of an independent review by Stone & Webster, Boston Gas revised its unaccounted for retention factor from 2.5 percent to 1.25 percent[139] (id. at 148-149). Fourth, the Company maintains that the use of average response time for odor calls could mask poor performance for a few visits, but appear acceptable (id. at 63-64, citing Tr. 12, at 26). Therefore, Boston Gas continues to advocate a 60 minute standard (id. at 64).

Fifth, the Company views the Walker customer surveys[140] as an internal measure that it uses to monitor its performance and contends that it may modify the surveys to track different indices (id.). If the surveys were included in the SQI, Boston Gas asserts that it

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139 The Company does not address whether it would be appropriate to add an SQI measure for unaccounted-for gas, but proposes a 1.25 percent retention factor for third-party gas deliveries (Company Brief at 149).

140 Walker customer satisfaction surveys measure the Company's customers's levels of satisfaction with its services (Exh. BGC-13, at 8).

would not be able to alter them, which would reduce their benefit to the Company (id., citing Tr. 12, at 15-16; Tr. 16, at 235-236).

Sixth, the Company claims that measuring the number of customer telephone inquiries and monitoring telephone contacts would require extensive record keeping (id. at 64). Boston Gas states that its proposed TSF factor sufficiently addresses this issue (id. at 64). Finally, Boston Gas claims there are ample statutes and regulations in place that govern meters (id., citing G.L. c. 164, §§ 103, 114, 115A).

Regarding DOER's recommendation to escalate the SQI penalty with earnings, the Company argues that this would result in a service quality penalty that could fall below the proposed penalty if the Company's earnings decline. According to Boston Gas, this would provide little incentive to maintain service quality (id. at 66).

Regarding the Attorney General's recommendation to set the SQI penalty at $6 million, or one percent of revenues, the Company argues that: (1) there is no record evidence to support his assertion; (2) the Attorney General's comparison to NYNEX's SQI penalty is inappropriate, since the telephone industry is different from the gas industry and since the NYNEX penalty is 3.7 percent of its return on equity (id. at 66, citing Tr. 3, at 127; NYNEX, Sch. 4, 5; Exh. BGC-39, at 3, 44); and (3) the Attorney General incorrectly included gas cost revenues in his calculation, to which the PBR does not apply (Company Brief at 66 n.26).

3. Analysis and Findings

The Department has previously stated that while the primary focus of any PBR should be to achieve cost reductions, the Department continues to recognize its mandate to ensure the continued delivery of safe and reliable service to the public. Incentive Regulation at 60.

The Department has also stated that well-designed PBR plans should include measurable performance indicators and targets to evaluate a program's effects on safety, reliability, and service quality. Id. at 63-64. In NYNEX, the Department found that because price cap regulation introduces a financial incentive for the regulated firm to reduce costs, a well-designed price cap plan must include some form of protection against a reduction in service quality for monopoly customers. NYNEX at 235. Boston Gas's proposed SQI responds to these concerns to some extent. The Department addresses the following components of the Company's proposed SQI: (1) customer service categories; (2) performance measures; (3) category weights; (4) determined weights; (5) penalty provisions; and (6) SQI formulas.

Regarding the Company's proposed customer service categories of safety, billing and service, the Department finds that they reasonably reflect customer service and quality of service and shall be implemented. However, the Department finds that certain modifications to the proposed performance measures along with their corresponding benchmarks and weights are necessary. In addition, the Department considers the incorporation in the SQI of additional measures.

First, the Company proposed that for the Class I and Class II odor calls performance measure, the Company would respond to 95 percent of these calls in one hour or less. The Attorney General and DOER argue that a 95 percent benchmark is too readily attainable and should be increased. In 1995, the Company indicated that it responded to 92.7 percent of all odor calls (Exh. BGC-13, at 27 (rev.)). While the Department believes that the Company already has an incentive to respond rapidly to odor calls due to potential consequences of failing to respond, we find that a benchmark of 95 percent provides a sufficient challenge to

Company personnel. Therefore, the Department finds the benchmark as proposed by Boston Gas to be reasonable. Regarding the recommendation of adding the average response time for odor calls, the Department notes that outliers in either direction can skew the result. A sufficiently high benchmark percentage provides adequate customer protection and any additional measure would be redundant. Therefore, the Department finds it unnecessary to include an average response time for odor calls measure in the SQI.

With respect to the Company's proposed measure and benchmark for lost time accidents, the Department finds that both the measure and benchmark are reasonable and shall be included in the SQI. No party opposed the use of either the measure or benchmark.

Regarding the Company's proposed TSF measure and benchmarks, Boston Gas has provided no basis for using a measure of 40 seconds or the benchmarks of 90 percent for emergency calls and 80 percent for billing and service calls. However, the Company has provided its most recent actual response times for answering emergency, billing and service calls within 15 seconds and within 30 seconds (Exh. DPU-103, at 2). Boston Gas has indicated that between March 1, 1996 and June 30, 1996, 93 percent of emergency calls, and 77 percent of both billing and service calls were answered within 30 seconds (id.). The Company has been answering more emergency calls within thirty seconds than the Company proposes to accomplish in 40 seconds (id.; Company Brief at 65). Additionally, Boston Gas stated that its Teloquent system, which was installed in January 1996, is designed to allow customer service personnel to assign priorities to each type of customer inquiry and respond accordingly (Exh. DPU-100, at 1). The Department anticipates that the Company's customer service personnel will become more efficient at answering customer telephone calls over time. Therefore, the Department finds that the proposed TSF measure and the corresponding

benchmarks are too low in consideration of the Company's actual experience. Accordingly, the Department finds that a 30-second response time for the TSF measure is reasonable. Furthermore, based on the Company's actual performance, the Department finds that the benchmark for emergency calls shall be 95 percent. As to Boston Gas's proposed 80 percent benchmark for billing and service calls, the Department finds that this benchmark is reasonable in consideration of the actual 77 percent response time percentage for these inquiries.

As to the Company's proposed measure for service appointments met on the same day and its benchmark, the Department finds that they are reasonable and shall be included in the SQI. No party opposed the use of either the measure or benchmark.

With respect to the Company's proposed measure of on-cycle meter reads, the Department finds that it is a reasonable measure to include in the SQI. However, in the past twelve months, the Company read meters on-cycle 93 percent of the time (Exh. DPU-100, at 1). Therefore, the Department finds that the proposed 92 percent benchmark assigned to the on-cycle meter reads measure is too readily attainable. Although a 100 percent benchmark may be unrealistic due to certain constraints[141] and because not all meters will be fitted with an AMR device (Exh. DPU-101), a benchmark greater than 92 percent must be implemented. The Department finds that a benchmark of 95 percent is reasonable given the AMR system that is now in place. DOER recommends including in the billing category a frequency of meter failures measure. There is no evidence on the record that this is a critical issue for customers; more meaningful is the speed with which the Company responds

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141 Constraints include adverse weather conditions, AMR device failure, and antenna or radio interferences (Exh. DPU-101).

to all service problems. The service measure and the Department's regulations address those issues sufficiently. Therefore, the Department will not include a meter failure measure in the SQI.

The Attorney General and DOER recommend that the Department require Boston Gas to include Department complaint statistics in its SQI. The Department's Consumer Division tabulates monthly statistics for all Massachusetts gas and electric companies of (1) new customer complaint cases by industry, by company, and by type of inquiry, (2) calls referred back to the utility company from the Department by industry, by company, and by type of inquiry, and (3) customer bill adjustments initiated by the Department. The Department finds that the complaint statistics provide valuable insight into the quality of service provided by the Company despite Boston Gas's argument that the numbers involve only a small percentage of its customers. These statistics provide a way of comparing Boston Gas's performance to that of other Massachusetts LDCs. While it is true that only a small percentage of its customers are represented, only a small number of customers should have complaints. Customers contacting the Department's Consumer Division are asked whether they have discussed the problem with the utility; if they have not done so, they are asked to first pursue the matter with the utility. Only after a company has had the opportunity to address the specific problem, but has done so unsuccessfully, will the Consumer Division handle a complaint and regard it as a complaint case. The Department finds that the Company shall include Department Consumer Division customer complaint cases as an SQI measure.[142] In 1995, Boston Gas's customer complaint cases were 47 percent of the total

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142 Cases arising from sanitary code violations shall be excluded from the calculation, since the Company has no control over such incidents.

amount for all Massachusetts LDCs (Exh. AG-112). Based on this historic performance, the Department finds it reasonable that the number of Department Consumer Division customer complaint cases for Boston Gas in a particular year shall be no more than 50 percent of the total number of customer complaint cases for all of the Massachusetts LDCs, including Boston Gas.[143] The Company shall also include Department Consumer Division customer bill adjustments as an SQI measure. In 1995, Boston Gas's customer bill adjustments were 63 percent of the total dollar amount for all Massachusetts LDCs (id.). Based on this historic performance, the Department finds it reasonable that the number of Department Consumer Division customer bill adjustments for Boston Gas in a particular year shall be no more than 65 percent of the total dollar amount of customer adjustments for all of the Massachusetts LDCs, including Boston Gas.

With respect to the Attorney General's proposal to include an unaccounted-for gas measure in the SQI, the Department finds that this issue is addressed in Section XII.D.3. As noted, the City of Boston and the Attorney General recommend including in the SQI a cast iron main replacement measure. The Company indicated that the Department's regulations subject it to substantial fines and penalties for failure to comply with such maintenance. The Department's Pipeline and Safety Division oversees the Company's compliance with the regulations relating to cast iron main replacement. 220 C.M.R. § 113.05. Because the Department expects that Boston Gas will remain committed to its cast iron main replacement during the term of the PBR, and will monitor this commitment via annual reports to the Department's Pipeline and Safety Division, the Department finds it unnecessary to

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143 Department statistics are measured on a calendar-year basis, while the SQI is measured on a July through June basis (Exh. BGC-13, at 25).

incorporate a cast iron main replacement measure in the SQI. The City of Boston also recommends including in the SQI a comparison of the number of repairs to the cost of pipe replacement and the cost of road maintenance. While it is important for the Company to coordinate with cities and towns to avoid performing nonemergency work on newly paved roads, such a measure does not fit properly in a customer-oriented SQI. Therefore, the Department will not include this measure in the SQI.

Regarding the inclusion of Boston Gas's customer satisfaction survey results in the SQI as recommended by DOER, the Company indicates that its customer satisfaction surveys are an internal measure that the Company may choose to modify over time. Because customer survey results can be inaccurate and unreliable, the Department finds that they are not a useful component of a well-designed SQI. Therefore, the Department will not include such a measure in the SQI.

Finally, the Attorney General recommends a price performance measure where Boston Gas's transportation rates would be compared to that of the national average. Including a cost benchmarking would introduce a price-related component to an otherwise non-price mechanism. The Department finds this unnecessary given the comprehensive nature of the price cap plan. Therefore, the Department will not include such a measure as part of the price cap plan.

With respect to calculating the total SQI, parties point out that Boston Gas could fail to meet one threshold but meet the overall SQI due to its proposed weighting system. The Department agrees with this argument and notes that this would provide a perverse incentive for the Company to invest in one aspect of its operations more than or in lieu of others. The result is that the manner in which the Company proposed to calculate is overall SQI lessens

the importance of each measure and benchmark. Therefore, the Department finds it appropriate to assess each measure separately and eliminate all weights.

Regarding the parties's arguments that the overall proposed penalty is too small and static, the Department agrees that a $1 million penalty is not sufficient incentive for a gas distribution company with revenues of approximately $300 million. Although the Company points out that the Attorney General incorrectly included gas revenues in its calculation of 1.0 percent of Boston Gas's revenues, the Department finds that a larger penalty is warranted. Each measure shall be assessed a possible penalty of $700,000, totalling $4.9 million.

None of the parties addressed the formulas associated with the Company's proposed SQI. The Department finds that they must be modified in order to accommodate the changes in the design of the SQI that the Department finds appropriate. First, the service quality index formula need no longer be employed, since there is no weighting of measures; each one stands alone. Second, the penalty formula must be applied to each measure's benchmark and the resulting penalties shall be totalled. The target index value shall be the specific benchmark for each measure, while the lowest value of the index shall be five percent below each benchmark percentage, i.e., revenues shall decrease by $140,000 for each one percent below each measure's benchmark achieved by Boston Gas.[144] The actual index value is the Company's achievement in a specific year for each measure. The maximum penalty will be $700,000 for each measure.

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144 Regarding the lost time accidents measure, for every one percent that Boston Gas's most recent three year running average incidence rate for lost time accidents exceeds that of the National Safety Council's report entitled Work Injury and Illness Rates, revenues shall be decreased by $140,000.

4. Conclusion

The following is a list of measures and benchmarks that shall be incorporated in the SQI:

Customer Category	Performance Measure	Benchmark/ Target Value
Safety	Class I and II odor calls responded to in 60 minutes or less	95%
	Three year running average for lost time accidents	Less than the three year average
Service	Telephone Service Factor - Calls answered within 30 seconds	95% - Emergency 80% - Service and billing
	Service appointments met on the same day requested	95%
	Department complaint statistics Consumer Division cases less than 50% of total	95%
	Department complaint statistics Consumer Division customer adjustments less than 65% of total	95%
Billing	Actual on-cycle meter reads	95%

E. Capital Cost Adjustment

1. The Company's Proposal

According to Boston Gas, major changes in debt and equity rates can produce significantly different capital costs from those incorporated in the price cap (Exh. BGC-3, at 24). In order to preserve its access to capital markets, the Company proposed a capital cost adjustment component for its price cap (id.; Tr. 3, at 48-49).

Under its proposed capital cost adjustment formula, Boston Gas would recalculate annually the initial price cap capital cost revenue requirement for the equity component of the Company's capital structure in each year where the annual average yield to maturity on 30-year Treasury bonds increases or decreases by 200 basis points or more during that year (Exh. BGC-3, at 28; Company Brief at 68).[145]

If in a given year the yield to maturity changes by 200 basis points or more from the yield to maturity in effect at the start of the price cap term, the following formula would apply:

$$CAP_t = \frac{\{RB_0 * Eq_0 * (TBond_t - TBond_0)\}}{1\text{-}CT_0}$$

Where:

CAP_t	=	Capital cost adjustment in year t;
RB_0	=	Rate base in year zero;
Eq_0	=	Percent of equity in year zero;
$Tbond_t$	=	Yield to maturity on 30-year Treasury bonds in effect in year t;
$Tbond_0$	=	Yield to maturity on 30-year Treasury bonds in effect in year zero; and
CT_0	=	Combined tax rate in year zero

(Exh. BGC-4, at 8).

The Company would apply the adjustment only to its rate base in existence as of the date of the plan, and would not apply it to any rate base additions made after that date

145 In its initial filing, the Company proposed that if the yield increased or decreased by 200 basis points or more on any single day, the capital cost adjustment would be applied (Exh. BGC-3, at 28; Tr. 3, at 50-51). On brief, Boston Gas modified its capital cost adjustment trigger mechanism so that the adjustment would be applied only if the yield increased or decreased by 200 basis points or more over the year (Company Brief at 68). The Company stated that this adjustment would mitigate the effects of short-term fluctuations in interest rates on the capital cost adjustment (id.).

(Exh. BGC-3, at 24-25; Tr. 3, at 49). The Company intends to accrue or reserve its capital costs for those years in which the yield to maturity exceeds or falls short of the current 6.5 percent rate by 200 basis points (Exh. BGC-3, at 28).

Without such a capital cost adjustment, the Company stated that it would be deprived of the ability to recover increased capital costs produced by inflation (id. at 27). To illustrate this, the Company prepared a comparative two-year analysis. The Company assumed for purposes of analysis an inflation rate of 4.0 percent in Year One, and an inflation rate of 6.5 percent in Year Two. In its analysis, Boston Gas assumed that in Year One its rate base would be \$460 million, and rise to \$468 million in Year Two. Boston Gas also assumed its nominal capital costs would be 8.0 percent for debt and 12.0 percent for equity, on a capital structure consisting of 50 percent debt and 50 percent equity, with real capital costs of 4.0 percent for debt and 8.0 percent for equity, and a 40 percent tax rate. Under these conditions, its return on rate base and associated income taxes under traditional cost of service regulation would be \$64.4 million in Year One, as illustrated by the following formula:

$$\$460.0 * \left\{\frac{50 \text{ percent} * 12 \text{ percent}}{1\text{-}40 \text{ percent tax rate}} + (50 \text{ percent} * 8.0 \text{ percent})\right\}$$

(id. at 26).

Assuming that the inflation rate increases by four percent in Year Two, and real capital costs remain constant, the Company stated that its nominal cost of equity and debt would rise to 16.0 percent and 12.0 percent, respectively (id.). Under these conditions, its revenue requirements resulting from the increased cost of capital and Boston Gas's

incremental net investment in non-revenue-producing assets would increase in Year Two by $15.3 million, as illustrated by the following formula:

$$\$460.0 * \frac{50 \text{ percent} * 4.0 \text{ percent}}{(1\text{-}40 \text{ percent tax rate})} = \$15.3$$

(id.).

The revenue requirement associated with its incremental rate base investment would be $1.5 million in Year 2, as illustrated by the following formula:

$$(\$468.0 - \$460.0) * \{\frac{50 \text{ percent} * 16 \text{ percent}}{1\text{-}40 \text{ percent tax rate}} + (50 \text{ percent} * 12 \text{ percent})\}$$

(id. at 27).

Thus, the total return requirement under cost of service regulation resulting from the increased cost of equity and Boston Gas's net incremental investment in non-revenue-producing assets would be $16.8 million in Year 2 (id.).

The Company compared this scenario to that which would occur under price cap regulation, as described in the following formula:

$$\$64.4 \text{ million} * 6.5 \text{ percent} = \$4.2 \text{ million}$$

(id.).

Therefore, Boston Gas concluded that without a capital cost adjustment provision, its capital costs would be understated by approximately $12.6 million (id.). The Company stated that while competitive markets can adjust prices to a certain extent to recognize

interest rate changes, the ability of these markets to do so is limited by the particular industry (Tr. 16, at 51-52).

2. Positions of the Parties

a. Attorney General

The Attorney General opposes the Company's proposed capital cost adjustment component (Attorney General Brief at 28). The Attorney General claims that Boston Gas's proposal constitutes a unique component not found in standard price cap formulas, and argues that such a mechanism is unnecessary because the Company has a degree of control over its capital costs (id.; Attorney General Reply Brief at 12). The Attorney General maintains that the capital cost adjustment component destroys the underpinnings behind the methods and incentives offered under price cap mechanisms (Attorney General Reply Brief at 11). The Attorney General contends that changes in the cost of capital would impact the economy as a whole, and not only the regulated local natural gas industry (id. at 28).

Moreover, the Attorney General argues that the Company overstates its claim of financial harm without the capital cost adjustment. The Attorney General notes that the term of the price cap is only five years and, therefore, any losses resulting would be short-lived (Attorney General Reply Brief at 12). The Attorney General contends that his proposed earnings sharing mechanism essentially would eliminate the risk of financial harm to Boston Gas (id.). The Attorney General further maintains that the Company's use of embedded depreciation, debt, and preferred stock rates to develop its "cast-off" point rates obviates the need for a capital cost adjustment component (id. at 12-13). The Attorney General reasons that if the capital cost adjustment component were permitted, the corresponding implicit costs

of depreciation, debt, and preferred stock should be reduced to reflect their true costs (id. at 13).

b. DOER

DOER also opposes the Company's proposed capital cost adjustment component (DOER Brief at 48-50). DOER maintains that an effective price cap mechanism should contain neither an automatic cost of capital adjustment, nor apply such an adjustment on a retroactive basis, as proposed by Boston Gas (id. at 50). DOER contends that the Company has included a substantial amount of post-test year investment in its proposed cast-off rates and has provided for a degree of protection from risk associated with non-revenue producing plant through the indexing features contained in the price cap's annual inflation component (id.). According to DOER, the effect of these components would compound annually, thus leading to progressively larger increases over time regardless of the level of capital spending by Boston Gas or actual changes in the cost of capital (id. at 49). Therefore, DOER maintains that even as modified, Boston Gas's proposal effectively insulates the Company from downside market risks (id. at 49-50; DOER Reply Brief at 9). DOER argues that with non-revenue producing investments built into the price cap indexing component, an earnings sharing mechanism as proposed by DOER and other parties would protect the Company from extreme, unforeseen variations in the cost of capital, rendering a cost of capital adjustment component unnecessary (DOER Brief at 50; DOER Reply Brief at 10).

c. AIM

AIM opposes the Company's proposed cost of capital adjustment component, and reasons that the proposed components of the price cap as a whole would serve only to ensure

annual rate increases and lessen the probability of creating efficiencies that would result in improved customer service (AIM Brief at 12).

d. MOC

MOC argues that the Company's proposed cost of capital adjustment component, like other elements of Boston Gas's price cap mechanism, serves to minimize the risks to the Company's shareholders (MOC Brief at 5). MOC contends that the cost of capital adjustment component is inconsistent with the both the Department's standards on incentive regulation and ratepayer interests (id. at 5-6).

e. The Company

Boston Gas contends that the capital-intensive nature of the local gas distribution industry makes it critical for the Company to maintain access to capital markets and earn a fair return on its investment, thus ensuring the continued operation of a safe, reliable distribution system (Company Brief at 67, citing Exhs. BGC-3, at 24; DPU-110; RR-DPU-58). In particular, the Company points to its relatively large construction program, mostly represented by non-revenue producing additions, as justification for its proposed capital cost adjustment component (id. at 67).

The Company maintains that other price cap plans have recognized capital costs as exogenous factors or incorporated "off-ramps" (id. at 67-68, citing Exh. BGC-28). Boston Gas faults the Attorney General and DOER for ignoring the symmetrical nature of the proposed adjustment and the protection it renders to ratepayers (id. at 68, citing Exh. BGC-3, at 24; Tr. 16, at 49). The Company notes that because the cost of capital price cap component is applied only to rate base in effect as of the start of the price cap plan, Boston Gas continues to bear the investment risks going forward (id.).

The Company states that it would be amenable to eliminating its cost of capital provision and to making a dollar commitment to its cast iron and bare steel main replacement program, if it could be assured that its price cap formula would capture the cost of these non-revenue producing investments (Company Reply Brief at 25). The Company maintains that the primary cause of its current revenue deficiency can be attributed to its capital expenditures program, and that the Attorney General's proposed treatment of non-revenue producing plant and capital costs would be both a losing proposition for Boston Gas and produce a chilling effect on the development of price cap regulation in the gas industry (id. at 25).

3. Analysis and Findings

To the extent that incentive ratemaking proposals emphasize cost recovery issues rather than strive to replicate market forces, these proposals may miss the point behind incentive ratemaking, e.g., to provide marketplace benefits to ratepayers by promoting more efficient utility operations, cost control, and opportunities for reduced rates. Incentive Regulation at 40, 62. The Department has noted that a well-designed PBR with clear objectives, consistently applied incentives, and an equitably apportioned sharing of risks and benefits between ratepayers and shareholders would be viewed positively by the investment community, thereby ensuring the utility's continued access to the capital markets. Incentive Regulation at 64.

Although the Company's proposal as modified addresses, to an extent, the concerns raised by various intervenors, associated with the impact of short-term market rates on its capital costs, Boston Gas has provided no persuasive evidence that its capital costs are significantly influenced by changes in the rates for 30-year Treasury bonds. Changes in the

required cost of capital would be, to a considerable extent, recovered through the operation of the inflation factor and appropriate shifts in the Company's capital structure. The Department is not persuaded that a capital cost adjustment is a necessary component to successful operation of the price cap mechanism. Accordingly, the Department hereby rejects the Company's proposed capital cost adjustment component.

F. Term of the Plan

1. The Company's Proposal

Under the Company's price cap plan, Boston Gas would commence price cap regulation as of December 1, 1996, to continue through November 30, 2001 (Exh. BGC-3, at 32). Thereafter, the Company anticipated that the price cap mechanism would continue in effect unless: (1) the Department, Company, or other parties seek modifications to the plan; and (2) the Department determines that modifications are necessary (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that, unless the Department includes an earnings sharing mechanism to the Company's price cap, as he and DOER propose on brief, the term of Boston Gas's price cap should be reduced to three years (Attorney General Brief at 29). This term, according to the Attorney General, would allow for adjustments to the price cap plan to correct any elements which were "mis-specified" in establishing the Company's original rates (id.).

b. The Company

Boston Gas argues that a three-year price cap would not allow sufficient time for the Company to operate under the plan and would be no different from the average elapsed time

between rate filings (Company Brief at 70). Consequently, the Company contends that the Attorney General's proposal would offer no administrative efficiencies or savings in regulatory costs, which Boston Gas characterizes as one of the primary benefits of incentive regulation recognized by the Department (id. at 70, citing Incentive Regulation).

3. Analysis and Findings

The Department has stated that one potential benefit of incentive regulation is a reduction in regulatory and administrative costs. Incentive Regulation at 64. Additionally, the Department has found that a well-designed price cap plan should be of sufficient duration to give the plan enough time to achieve its goals, and to provide utilities with the appropriate economic incentives and certainty to follow through with medium- and long-term strategic business decisions. Incentive Regulation at 66; NYNEX at 272.

The Department finds that the Attorney General's three-year term is too similar in duration to the Company's typical interval between traditional base rate filings to accrue any benefits resulting from PBR. In light of this, and the inclusion of an earnings sharing mechanism below, the Department declines to accept the Attorney General's proposed price cap term. The Department finds that the Company's proposed five-year term will provide a sufficient period to evaluate administrative efficiencies and to allow Boston Gas the level of certainty required to enter into business decisionmaking. Consistent with our findings in Section XIII.C.2 of this Order, the Department finds that the initial annual adjustment of the Company's price cap mechanism will take effect on November 1, 1997, with successive annual adjustments through 2001. Depending upon the results of this evaluation, the plan may be extended without modification for an additional term, extended with modifications, or terminated.

G. Earnings Sharing

1. Positions of the Parties

a. The Attorney General

According to the Attorney General, the Department should require earnings sharing for any price cap plan that it puts into effect (Attorney General Brief at 14). The Attorney General asserts that earnings sharing provides protection against the adoption of productivity factors that are incorrect either from the beginning of the plan or over the term of the plan (id. at 15). The Attorney General advocates an earnings sharing mechanism which provides a deadband range of six percent to twelve percent return on common equity, inclusive (id.). Above that range, and up to and including a 20 percent return on common equity, the Attorney General recommends an earnings sharing of 75 percent and 25 percent by the ratepayers and shareholders, respectively. Above a 20 percent return on common equity, the Attorney General recommends that incremental earnings be shared 25 percent and 75 percent by the ratepayers and shareholders, respectively. If the Company's return on common equity falls below 6 percent, the Attorney General recommends that the incremental earnings deficiency (the difference between the earned return and six percent) be shared 50 percent by ratepayers and shareholders, respectively (id.).

b. AIM

AIM recommends that the Department incorporate an earnings sharing mechanism in Boston Gas' price cap plan (AIM Brief at 8). AIM points out that although the Department rejected such a mechanism in NYNEX, the Department did not reject the concept of earnings sharing altogether (id.). In addition, AIM contends that Boston Gas' plan does not provide the same ratepayer benefits as NYNEX, such as a residential customer rate freeze and price

flexibility limitations (id.). Therefore, according to AIM, the lack of an earnings sharing mechanism will provide excessive benefits to the Company (id.).

c. DOER

DOER advocates the inclusion of an earnings sharing mechanism for the term of the price cap plan (DOER Brief at 20). DOER maintains that a static price cap formula, as proposed by the Company, would not respond to the changes in the level of productivity Boston Gas is expected to experience as a result of the rapid evolution of the natural gas industry, with the advent of unbundling, increased competition, and performance-based regulation (id.). Therefore, DOER asserts that the implementation of earnings sharing is a necessary component to protect the Company's ratepayers (id.). Specifically, DOER proposes that the Department establish a 200 basis point bandwidth around the Company's authorized rate of return (id.); the ratepayers and shareholders would each share 50 percent of any fluctuations, which fall 200 basis points above or below Boston Gas's authorized rate of return (id.).

DOER notes that although the Department did reject an earnings sharing mechanism in NYNEX, the Department did not foreclose the possibility of integrating such a component in incentive plans the Department might adopt for other utilities (id. at 24, citing NYNEX at 197 n.116). Further, DOER asserts that the Company's argument that earnings sharing is contrary to "national precedent" overlooks earnings sharing mechanisms proposed by other gas and electric utilities, and is based solely on price cap plans approved for the telecommunications industry (DOER Reply Brief at 2). DOER urges the Department to consider the differences between the NYNEX and Boston Gas plans (DOER Brief at 25). In addition, DOER maintains that the Company's claim that earnings sharing would

"destabilize" rates is disingenuous, because earnings sharing would only "destabilize" higher rates (DOER Reply Brief at 3). DOER points to the testimony of Dr. Candell stating that an earnings sharing mechanism would avert an upward trend in rates (id.,citing Tr. 18, at 58).

DOER argues that while the NYNEX plan contains significant ratepayer benefits, e.g., a price freeze for residential customers and limitations on pricing flexibility, those features are absent from Boston Gas's proposal (DOER Brief at 25). Further, DOER contends that the NYNEX plan provides the opportunity to realize a higher return based solely on NYNEX's increased efficiencies; in contrast, DOER argues that Boston Gas's price cap plan would result in higher returns to its shareholders based on factors other than the Company's efficiency gains (id. at 25). DOER avers that the Company's plan insulates its shareholders from investment risks, and, therefore, is contrary to the Department's finding in NYNEX that ratepayer insulation from investment risks is a fundamental advantage of a well-structured price cap plan (id., citing NYNEX at 137). In light of the foregoing, DOER maintains that an earnings mechanism must be incorporated in the Boston Gas price cap plan (id. at 25).

DOER recognizes that the Department has stated that one of the goals of incentive regulation is administrative simplicity; however, DOER indicates that in NYNEX the Department acknowledged that an additional administrative burden would not be a concern, if there is a corresponding benefit to ratepayers (id. at 26, citing NYNEX at 199). To minimize the administrative burden associated with the implementation of an earnings sharing mechanism, DOER suggests that the Department establish in advance the specific and verifiable data the Department would require for a review of earnings (id. at 26). DOER alleges that under its proposed PBR plan, any additional review required in the compliance

filing represents a simple trade-off for the protection for ratepayers inherent in the earnings sharing mechanism (id. at 27).

d. ComGas

ComGas supports the incorporation of a symmetrical earnings sharing mechanism. ComGas argues that in the early stages of implementing a price cap formula, earnings sharing provides a mechanism to avoid any unintended consequences of PBR (ComGas Brief at 22).

e. The Company

Boston Gas asserts that its proposal not to include an earnings sharing mechanism in its price cap plan is consistent with the Department's findings in NYNEX (Company Brief at 70). According to the Company, earnings sharing creates administrative burdens, and "destabilizes" rates (id.; Company Reply Brief at 26). First, Boston Gas claims that earnings sharing mechanisms necessitate reviews of earnings, investment decisions, and prudence, thus imitating cost of service regulation that PBR plans strive to eliminate (Company Brief at 70-71). Second, Boston Gas maintains that customers care about stable prices and that DOER admitted that an earnings sharing mechanism would not only "destabilize" rates, but increase rates beyond inflation if the Company experiences losses (id. at 71-72, citing Tr. 18, at 26). The Company also states that the Attorney General's and DOER's recommended bandwidths and sharing percentages are unsubstantiated by the record (id. at 73).

2. Analysis and Findings

The Department did not reject the concept of earnings sharing in NYNEX. Although earnings sharing was not implemented for NYNEX, the Department stated:

> While we find, based on the record in this proceeding, that it would not be appropriate to include earnings sharing or an earnings cap in the price cap for NYNEX, such a finding should not be construed as an absolute rejection of these concepts. On the contrary, earnings sharing and/or earnings ceilings may be integral components of incentive regulation plans that we approve for other utilities.

NYNEX at 197 n.116.

In the instant proceeding, the Attorney General's assertion that earnings sharing provides protection against the adoption of incorrect productivity factors for Boston Gas is a compelling argument in support of earnings sharing. The Department previously has recognized the issue of uncertainty associated with setting the productivity factor and stated that earnings sharing provides a backstop to the productivity factor. Id. at 197. The Department finds that in this case such protection is required for the Company's customers and is desirable to protect the Company from potential earnings losses as well. Based on the record, the Department finds that it is likely that there would be a benefit in implementing earnings sharing because of our concern with the uncertainty regarding the Company's future productivity.[146]

With respect to the arguments of the parties on earnings sharing, the Company's argument that earnings sharing "destabilizes" rates is wholly unpersuasive, since rates would change with any yearly adjustment brought about by the price cap formula. In addition, DOER correctly points out that the Department has stated that the additional administrative burden of incorporating earnings sharing would not be a concern for the Department if there were a corresponding benefit. Id. at 199.

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52 The Department anticipates that over time, more information regarding productivity in the gas distribution industry will reduce the level of uncertainty.

Therefore, the Department finds that the implementation of an earnings sharing mechanism for the term of the price cap plan is appropriate. However, the Department is concerned with the restrictive nature of both the Attorney General's and DOER's proposed earnings sharing ratios in that they can overly dilute the Company's economic incentives. Moreover, based on the Department's authorized return on common equity of 11 percent, the Attorney General's recommended return on common equity bandwidth of 6 to 12 percent is too asymmetrical. Accordingly, the Department rejects both the Attorney General's and DOER's proposals. The Department finds it more reasonable to implement an earnings sharing plan with a Company/ratepayer sharing ratio that provides Boston Gas with economic incentives and a bandwidth that balances Company and ratepayer risks. Therefore, the Company shall put in place an earnings sharing plan that sets a 400 basis points bandwidth around the Company's authorized return on common equity of 11 percent. If the Company's earned return on common equity in a particular year falls within the range of 7 to 15 percent, there will be no earnings sharing. If the Company's actual return on common equity is below 7 percent, the shareholders and ratepayers will share the loss 75 percent and 25 percent, respectively. To the extent that the Company experiences a return on common equity above 15 percent, the shareholders and ratepayers will share the gain 75 percent and 25 percent, respectively.

H. Pricing Flexibility

1. The Company's Proposal

Under the Company's price cap proposal, Boston Gas would retain discretion in allocating each rate class's price cap increase to the individual rate elements within the class

(Exh. BGC-3, at 43).[147] According to the Company, this rate design flexibility is essential to reduce intraclass subsidies (Exh. BGC-3, at 43). Boston Gas proposed to accomplish this by increasing customer charges annually, during the term of the price cap plan, until the customer charges reflect full embedded customer-related costs (Exh. BGC-3, at 43).[148] The Company would retain the discretion in setting each class's volumetric rates to recover the revenues not recovered through the class's customer charge.

2. Positions of the Parties

a. Attorney General

The Attorney General opposes the Company's proposal for intraclass pricing flexibility (Attorney General Brief at 13). The Attorney General notes that Boston Gas is a monopoly supplier of gas services, and will continue to operate as such during the term of any PBR plan approved in this proceeding (id. at 13, 29). The Attorney General argues that Boston Gas as a monopoly provider, could exert a tremendous amount of market power over the term of the PBR (id. at 29). Therefore, the Attorney General advocates that all increases granted during the term of the PBR be allocated only at the rate of change provided for in the price cap formula (id. at 8). The Attorney General contends that if the Company believes a particular rate class is not recovering its full embedded costs, it is free to petition

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147 In its initial filing, Boston Gas proposed that the Department grant the Company discretion in allocating the price cap increase to the individual rate classes, with the provision that no rate class's increase would exceed one and one-half times the GDP-PI for that year, excluding increases associated with exogenous costs and its capital cost provisions (Exh. BGC-3, at 43). On brief, Boston Gas withdrew its proposed interclass rate flexibility provision, noting that any reallocation of class revenue requirement could be addressed at the review of the PBR mechanism (Company Brief at 80).

148 A schedule of the Company's proposed customer charges is set forth in Exhibit BGC-95.

the Department for a readjustment and full review of these rates at the end of the term of the PBR (id. at 30).

b. DOER

DOER opposes the Company's proposed pricing flexibility component (DOER Brief at 43-44; DOER Reply Brief at 9). DOER states that Boston Gas's proposed modification to price flexibility, made on brief, remains unclear (DOER Reply Brief at 9). DOER contends that, if the Company intends to limit rate increases for a particular class to the price cap index, the Company's modification fails to address the issues of accumulated foregone increases and interclass revenue allocations (id. at 9).

With respect to customer charges, DOER contests the Company's rationale for moving customer charges toward embedded costs, and argues that the proposal is overly ambitious and detrimental to customers (DOER Brief at 46). As illustration, DOER notes that under the Company's proposal, customers could experience increases of as much as 16.5 percent on a total bill basis (id. at 46).

With respect to Boston Gas's proposal to increase customer charges over the term of the PBR, DOER argues that this violates the Department's five rate design goals of efficiency, simplicity, continuity, fairness, and earnings stability (id., citing D.P.U. 92-111, at 283; DOER Reply Brief at 10). According to DOER, the Company's proposal will not produce stable prices for customers, but will result in "stable price increases on an annual basis" (DOER Reply Brief at 9-10). Therefore, DOER argues that any increase in rate elements should be limited to the rate of inflation (DOER Brief at 46-47).

c. AIM

AIM maintains that the pricing flexibility component of the Company's PBR proposal will adversely affect residential and small commercial and industrial customers by subjecting them to rate impacts that violate the Department's standards on rate continuity (AIM Brief at 11). AIM argues that because Boston Gas will continue to be the monopoly provider of transportation services in its service territory, the Company should not be allowed any rate flexibility as part of a PBR proposal (AIM Reply Brief at 3-4).

AIM contends that, despite the Company's expressed willingness to relinquish inter-core rate class pricing flexibility, the banking provisions of the PBR would continue to allow Boston Gas to allocate different increases to different rate classes over time (id. at 3). Moreover, AIM argues that Boston Gas's proposal fails to address intraclass flexibility in that a particular customer may experience an average increase materially different from the rest of the class (id.).

d. MOC

MOC opposes the Company's proposal to increase customer charges to embedded cost levels over the term of the PBR (MOC Brief at 26). MOC argues that this will disproportionately affect low-use customers and violate the Department's ratemaking principles of continuity and stability (id. at 26-27; MOC Reply Brief at 3-4). According to MOC, low-use customers will perceive the PBR mechanism as merely a vehicle used to increase their rates, instead of a means to increase utility efficiency (MOC Brief at 28; MOC Reply Brief at 4). Therefore, MOC advocates that all increases granted as part of this proceeding and during the term of the PBR be allocated in an across-the-board manner equally to all rate classes and their respective components (MOC Reply Brief at 4).

MOC also contends that the Company's pricing flexibility and transportation rate proposals raise the issue of predatory pricing (MOC Brief at 25; MOC Reply Brief at 5). According to MOC, predatory pricing is defined as occurring when a product is priced below an appropriate measure of the challenged party's total costs (MOC Brief at 22-24, citing Brook Group Ltd. v. Brown and Williamson Corp., 113 S.Ct. 2578, 2586-2587 (1993) ("Brook Group") 15 U.S.C. § 2, 15 U.S.C. § 13(a)). MOC argues that the Supreme Court has left the definition of appropriate pricing to individual cases, and notes that federal courts have found that prices above average costs could be deemed to be predatory prices (id. at 24-25, citing Cargill, Inc. v Monfort of Colorado, Inc., 107 S. Ct. 484 (1986), Transamerica Computers v. IBM, 698 F. 2d 1377 (9th Cir.) (1983); MOC Reply Brief at 6).

MOC observes that regulated public utilities are immune from antitrust liability by virtue of their operation pursuant to a clearly articulated state policy (MOC Brief at 25). Therefore, MOC argues that the Company's pricing standard must be rejected to protect ratepayers, the competitive oil heat market, and the general public (id. at 25-26). MOC maintains that the record supports a finding that the Company seeks to strengthen its market presence through flexible pricing and competitive services pricing (MOC Reply Brief at 5). MOC emphasizes that, although the Company is actually engaging in predatory pricing, this determination will have to be made by a court of law; however, given the Department's intention of allowing consumers to benefit from increased competitive choices, any regulatory scheme approved by the Department cannot allow Boston Gas to retard the market at the detriment to ratepayers (id. at 6-7).

e. NEEC

NEEC contends that Boston Gas is seeking significant increases in customer charges (NEEC Brief at 4, citing Exhs. BGC-75, at 10-11, 14-18, 22-23; BGC-95). NEEC argues that these proposed increases violate the Department's principles of rate continuity, create inequitable outcomes for smaller customers, and create a strong disincentive to the implementation of energy efficiency measures (id. at 5).

f. TEC

TEC argues that the Company's proposed pricing flexibility is unnecessary and unwarranted (TEC Brief at 7-8). TEC maintains that under the Company's proposal, Boston Gas would have the discretion to apply rate increases to any component of the respective rates, thereby creating the possibility that one group of customers could be adversely affected (id. at 8, citing Exh. TEC-13, at 8). Therefore, TEC advocates that all increases granted during the term of the PBR be allocated in an across-the-board manner equally to all rate classes and their respective components (id.). TEC contends that if the Company believes rate design changes are necessary, it should be required to file a rate design case with the Department so that various interested parties would have the opportunity to review the filing and to ensure that the Company demonstrates its burden of proof (id.).

g. The Company

Boston Gas maintains that its proposal to increase customer charges to embedded levels over the term of the PBR is consistent with the results of its embedded cost studies performed in accordance with Department precedent (Company Brief at 81). According to the Company, its embedded cost studies demonstrate that the embedded cost of its Rate R-1 customer charge is $11, and that the embedded cost of its Rate R-3 customer charge is $25

(id. at 82).[149] Because of bill impact and continuity concerns, the Company contends that it will move customer charges toward embedded costs in a gradual manner, consistent with the schedule set forth in Exhibit BGC-95 (id. at 81).

The Company argues that the Attorney General's and NEEC's concerns about rate impacts on low-use customers must be put into context, because these customers referred to by the Attorney General represent about three percent of the total R-3 class (id. at 82). Boston Gas maintains that the Attorney General's proposal would serve only to perpetuate intraclass subsidies (id. at 82-83). Moreover, the Company argues that the rate increases to which NEEC objects are properly allocated to low-use customers, who impose a level of costs on the Company's system regardless of their use (id. at 83). Boston Gas contends that its rate design proposal moves rates closer to their cost structures, increases price signal efficiency, and encourages energy efficiency measures that have the greatest economic impact (id.).

With respect to MOC's objections to marginal cost pricing, Boston Gas argues that its use of marginal cost pricing to establish tailblock rates, set a customer charge, and price the residual revenue requirement through a headblock charge, is consistent with Department ratemaking policy (id. at 84, citing D.P.U. 93-60, at 331; D.P.U. 92-78, at 116; D.P.U. 1720, at 112-120). The Company contends that MOC's concerns about predatory pricing logically are flawed, because pricing of elastic use at marginal costs produces more efficient and fair pricing that is reflective of cost causation, and does not result in cross-subsidies or predatory pricing (id. at 84).

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149 Currently, the Rate R-1 and Rate R-3 monthly customer charges are $7.00 and $8.50, respectively (Exh. BGC-83, at 1).

Furthermore, Boston Gas argues that MOC's antitrust arguments fail to consider that a finding of predatory pricing requires a showing of intent to eliminate or retard competition, which the Company claims is absent from this record (id., citing Brook Group). The Company goes on to contend that the Brook Group decision requires a showing that the defendant's costs are below "an appropriate measure," and that the defendant has a reasonable prospect of recovering its investment in below-cost prices (id. at 85-86, citing Brook Group at 2588; Department Brief in Massachusetts Oilheat Council v. Department of Public Utilities, Commonwealth of Massachusetts Supreme Judicial Court, No. 6359). According to Boston Gas, MOC has failed to make these showings on the record and failed to demonstrate the likelihood that this situation could occur (Company Brief at 86).

3. Analysis and Findings

The Department agrees with the Company that it should retain some discretion in allocating the price cap increase between rate elements within a class. Allowing Boston Gas to set the rate component charges within a class should help to reduce intraclass subsidies and high bill impacts for individual customers.

However, the Department also recognizes, as does the Attorney General, that Boston Gas will continue to operate as a monopoly provider during the term of the PBR plan. Consequently, the Company has the ability to exert a tremendous amount of market power over the term of the PBR. In addition, were the Department to allow the Company to allocate the price cap increase or decrease within a class at its discretion, this would increase the time needed to investigate the compliance tariffs.

However, the proposal to adjust all rate component prices at the rate of change provided for in the price cap formula, which is supported on brief by the Attorney General,

AIM, MOC, and TEC, would not enable the Company to reduce intraclass subsidies and increase price signal efficiency. Therefore, the Department finds that imposing such a requirement on the Company would be overly restrictive.

The Department finds that a more appropriate alternative, as advocated by DOER, would be to allow the Company to allocate the price cap increase or decrease within a class at its discretion as long as no rate component increases by more than the rate of inflation. This alternative is consistent with our decision in NYNEX, D.P.U. 94-50, at 216 (1995). This proposal gives the Company some intraclass rate discretion, while ensuring that each individual rate element cannot increase above the inflation rate for the duration of the plan.

Therefore, the Department rejects the Company's proposed customer charges set forth in Exhibit BGC-95. Instead, the Department finds that Boston Gas shall allocate the price cap increase or decrease within a class at its discretion, as long as no rate component increases by more than the rate of inflation. Should the price cap increase be greater than the rate of inflation, because of the recovery of exogenous costs, the Department directs the Company to increase each rate component price at no more than the rate provided for in the price cap formula.

The Department will now address MOC's concern regarding predatory pricing. The Department has approved special contracts and economic development rates for incremental load customers, which are priced below full embedded cost but above incremental or marginal cost. See January 10, 1996, Letter-Order, Boston Gas Company; Bay State Gas Company, D.P.U. 92-68 (1992). The Department has found that a rate charged to an incremental load customer that exceeds marginal cost leaves no residual costs to be borne by remaining customers and provides an economic profit to the utility. D.P.U. 92-259, at 31.

Accordingly, the Department has found that marginal cost pricing does not violate the Department's monopoly regulation goal of fairness. Id. at 32.

Moreover, the Supreme Judicial Court has upheld the Department's marginal cost method to establish minimum rates for noncore customers. Massachusetts Oilheat Council v. Department of Public Utilities, 418 Mass. 798, (1994). The Department finds that prohibiting the Company from pricing any rate component below its marginal cost will prevent the Company from engaging in anticompetitive pricing, and thus resolves the concerns expressed by MOC.

I. Accumulation of Foregone Increases

1. The Company's Proposal

According to Boston Gas, competitive conditions may preclude it from fully implementing the allowed price increase for a particular rate class in any given year (Exh. BGC-3, at 29). Therefore, the Company proposes that it be permitted to carry over, or bank, any portion of a rate class's allowed price increase not applied in a particular year to a future year, so that the class's maximum adjustment for the subsequent year would reflect both the current year's adjustment and the price increase deferred from the previous year (Exhs. BGC-3, at 29; BGC-5, at 10; Tr. 16, at 166). Under the Company's proposal, increases banked from previous years could be deferred without time limitation (Exh. DOER-25). The Company stated that its banking provision would eliminate the incentive to always apply the maximum increase allowed under the price cap formula, and allow the opportunity to provide benefits to customers (Exh. BGC-3, at 29; Tr. 3, at 130-131).

2. Positions of the Parties

a. Attorney General

The Attorney General opposes the Company's proposed banking provision (Attorney General Brief at 30). The Attorney General argues that, to the extent that an annual price increase is not fully implemented by the Company, this would demonstrate that Boston Gas's rates are sufficient to recover their costs (id. at 31). The Attorney General states his opposition to allowing Boston Gas to increase rates to recover implied cost increases which did not occur (id.).

b. DOER

DOER characterizes the Company's banking provision as the "most egregious example" of how Boston Gas would be able to allocate sizable rate increases to customers (DOER Brief at 47). DOER urges the Department to reject Boston Gas's request for two reasons. First, DOER argues that banking increases is inconsistent with the concept that incentive regulation is designed to expose utilities to competitive markets (id., citing NYNEX at 105). Second, DOER contends that, although the price cap approved in D.P.U. 94-50 incorporates a banking feature, the Company's request for a banking feature merely exacerbates the potential problem arising from Boston Gas's request for pricing flexibility (id. at 47-48). DOER notes that the Company's overall price cap proposal provides fewer benefits and protections for residential customers than the price cap approved in NYNEX (id.).

c. AIM

AIM argues that the Department should reject the Company's banking proposal (AIM Brief at 12). AIM contends that this element, combined with other elements of Boston Gas's

price cap mechanism, ensures annual rate increases to customers while reducing the probability that service improvements can be achieved through greater efficiencies (id.).

d. The Company

Boston Gas maintains that its banking provision provides the Company with the proper incentives to keep rates for core customers down (Company Brief at 69). The Company asserts that without the banking provision, annual price adjustments would have a "use or lose" nature which would provide a perverse incentive in favor of using the full price increase, thus denying customers the opportunity to enjoy the benefits of lower prices in a given year (id.). Moreover, Boston Gas contends that its decision to withdraw its proposal for interclass rate flexibility should dispel any concerns about the propriety of its banking provision (id.).

3. Analysis and Findings

Through the Company's banking proposal, Boston Gas appears to seek authority to recover all price increases as derived from the price cap formula, whether in the then-current period or at some later date. Traditional ratemaking affords utilities a reasonable opportunity to recover prudent and verifiable expenditures made pursuant to legal obligations. On the other hand, incentive regulation seeks to harness the profit motive to further specific regulatory goals and move away from the traditional concepts of "cost recovery." Incentive Regulation at 61.

Boston Gas's stated intent that in the absence of a banking provision, it would have an incentive to collect the maximum level of price increases possible (Company Brief at 69), runs directly counter to incentive ratemaking concepts. Under traditional cost of service regulation, the utility has the discretion of deciding whether and when to file a general rate

case. D.P.U. 88-135/151, at 28. A utility whose earnings may not be producing a reasonable rate of return may choose to defer filing a general rate case for a variety of reasons, including economic conditions. Similarly, a utility under price cap regulation may find that market conditions preclude the application of the maximum price increase permitted under a price cap formula in a given year.

Accordingly, the Department rejects the Company's proposed banking provisions. If the Company elects hereafter to implement the maximum allowable price increase regardless of market conditions, then it will bear the responsibility for whatever consequences arise, such as customers leaving Boston Gas's system in favor of other energy sources.

J. Annual Compliance Filings

Under the Company's price cap mechanism, Boston Gas will file tariffs annually reflecting the price adjustments under its plan on or before September 15 to take effect on November 1 of each year (Exh. BGC-3, at 47). The Company intends to submit documentation supporting the price adjustments, including: (1) the determination of normal billing determinants and revenues to determine the weighted average price to which the price cap will be applied; (2) a calculation of the new price cap, including documentation of the exogenous factors and capital cost changes; (3) development of new rates consistent with the annual price cap calculation; and (4) class-by-class bill impacts, including gas costs, comparing the proposed rates to the then-current rates (id. at 47; Exh. BGC-9). The Company's weighted average price for the previous year would be calculated using revenues and billing determinants normalized for weather and adjusted for savings from implementation of the Company's DSM programs.

In order to minimize customer confusion resulting from consecutive rate changes arising with the semi-annual CGAC factor, Boston Gas proposed that price changes taking effect between 1997 and 2001 would be implemented on November 1 in each year, in conjunction with the change in the CGAC factor (Exh. BGC-3, at 32). None of the parties submitted briefs on either the issue of the content of the annual compliance filings or on the date of the annual price adjustments.

Based on the record before us, the Department finds that the information the Company proposes to provide will afford the Department and potential intervenors the opportunity to evaluate the Company's annual compliance filings. In making this finding, we emphasize that to the extent the Company submits the annual filings in a clear and comprehensive manner, with supporting data, this will facilitate the review of such filings by the Department and other parties. See South Egremont Water Company, D.P.U. 94-161, at 5 n.4 (1995).

The Department also finds that the Company's proposal to implement its annual price changes under the price cap as of November 1 of each year concurrent with the implementation of the semiannual CGAC factor will reduce customer confusion which would occur if price cap changes were not timed in conjunction with changes in the CGAC. Accordingly, beginning in 1997, price cap rate changes shall take effect on November 1 of each year.

XIII. INITIAL PBR-BASED RATES

A. Proposal of the Company

1. Development of Initial Rates

Boston Gas proposed a starting revenue of $277,047,067 to which it would apply its price cap formula (Exhs. BGC-6; BGC-9; RR-AG-59).[150] The Company based this starting point on its requested revenue requirement increase, which the Company then reduced to remove both costs that are excluded from the plan and the value of those services that the Company considered competitive (Exh. BGC-3, at 44-45). The Company stated that there were two essential considerations in the development of its price path (id. at 46). First, the Company intended to adjust its monopoly distribution service consumption data from the prior year for weather variations, the number of billing days, and its DSM energy efficiency programs (id.; Tr. 3, at 108). Second, the Company noted that it would update the relative weight factors for weather and customer mix to determine the base average price to which the price path is applied (Exh. BGC-3, at 46; Tr. 3, at 109; RR-DPU-1).

To determine this starting point, Boston Gas first determined that its revenue requirement was $662,007,706 (Exhs. BGC-6; BGC-39).[151] The Company then added $2,569,226 to reflect the following adjustments: (1) $2,528,360 in FAS 106-related adjustments which the Company is phasing in through November 1, 1996, pursuant to

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[150] Boston Gas's initial filing uses a starting revenue of $276,449,686; as explained below, the Department has developed for purposes of this section the starting revenue based on the Company's revised accounting exhibits, and revised the calculations accordingly.

[151] The Company's exhibits on this issue are based on the initially proposed revenue requirement of $661,410,322 (Exhs. BGC-6; BGC-39). For purposes of this section, the Department will use the Company's revised revenue requirement of $662,007,706 (RR-AG-59).

D.P.U. 93-60; and (2) $40,869 in cash working capital and income tax effects (Exhs. BGC-3, at 44-45; BGC-6). The Company then removed $376,427,430 in CGAC-related items to derive a distribution cost of service of $288,149,502 (Exh. BGC-6).

The Company further reduced its distribution cost of service by $9,101,687, representing $4,691,087 in test year margins associated with its Trigen Boston, Wellesley College, MATEP, and Brandeis University contracts, and $4,410,600 in annualized demand charges arising from the Company's current contract with BECo (Exhs. BGC-3, at 39; BGC-6). Boston Gas explained that under traditional ratemaking, these contract revenues would be excluded from its revenue requirement (Exh. BGC-3, at 39-40). However, the margins associated with these contracts are credited to core customers using a rate base allocator (Exh. BGC-111, at 4, Sch. R-8). Additionally, because Boston Gas considered its D.P.U. 92-259 contracts to be competitive, the Company proposed to remove the associated revenues from its core revenue requirement (Exh. BGC-3, at 40; Tr. 3, at 39-40).[152] The Company also excluded from its distribution cost of service an additional $2,000,748, representing $1,998,179 associated with Boston Gas's proposal to "buy" its interruptible transportation market and $2,569 in VNG margins (Exhs. BGC-3, at 40; BGC-6).[153] Therefore, the Company determined that its total monopoly distribution service revenues were $277,047,067 (Exh. BGC-6; Tr. 3, at 52).

Next, Boston Gas divided its monopoly distribution service revenues by its proposed normalized sales volume of 717,755,453 therms, resulting in a base average price of $.3860

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152 The Company reported that it earned no margins from D.P.U. 92-259 contracts during the test year (Exh. BGC-3, at 40; Tr. 3, at 40).

153 Boston Gas earned no margins from its D.P.U. 92-259 contracts during the test year (Exh. BGC-3, at 40).

per therm (Exh. BGC-6). Using its proposed price cap inflation component of 2.55 percent, less a productivity factor of 0.10 percent, the Company determined that its annual price path was 2.45 percent (id.). Application of the 2.45 percent price path to the base average price of $.3860 per therm resulted in a price path of $.3955 per therms, for an increase of $6,825,215 (id.; Tr. 3, at 52-53). Therefore, the Company proposed that its cast-off rates include $6,825,215 in price cap-related revenues effective December 1, 1996 (Exh. BGC-3, at 46).

2. Effective Date

Boston Gas proposed that the Department permit the rates approved herein to take effect on December 1, 1996 for all bills rendered on or after the date of the Department's Order, versus the standard of consumption on or after the date of the Order (id., at 45; Tr. 16, at 63-64). The Company stated that it originally intended and was prepared to submit its application in April of 1996, but delayed its filing for 30 days at the request of various parties (Exhs. BGC-1, at 5; BGC-3, at 45; Tr. 16, at 64-65). According to Boston Gas, the Company agreed to the delay to allow various stakeholders an opportunity to review the proposed filing and offer comment (Exhs. BGC-1, at 5; BGC-3, at 45; Tr. 16, at 64). The Company claimed that this review process resulted in significant modifications to the price cap proposal, and that both Boston Gas and most stakeholders acknowledged the process has been beneficial (Exhs. BGC-1, at 6; BGC-3, at 45). The Company requested that in consideration of this effort, the Department not require bills to be prorated (Exh. BGC-3, at 45; Tr. 16, at 65).

B. Positions of the Parties

1. Attorney General

The Attorney General contends that, notwithstanding the Company's treatment of post-Order increases in payroll and inflation, Boston Gas's proposal to implement its price cap as of December 1, 1996 is tantamount to double-recovery (Attorney General Reply Brief at 3). The Attorney General argues that the concurrent application of a price cap mechanism on rates which have been newly revised under cost-of-service regulation is contrary to the intention of price cap regulation and Department precedent (id.). According to the Attorney General, price caps are by nature not an adjustment to cost of service or an add-on to revenue deficiencies, but are applied to rate levels that have been previously set (id. at 4, citing NYNEX at 139-140, 193-197; Exh. BGC-39, at 35). The Attorney General argues that the Company's numerous cost of service adjustments, including its proposed return on common equity and inflation allowance, provide ample mitigation of the effects of inflation and attrition on Boston Gas's earnings (id. at 4-5). Therefore, the Attorney General advocates that any price cap mechanism not be applied until, at the very earliest, December of 1997 (id. at 5).

2. DOER

DOER opposes the Company's proposal to implement its price cap increase on the date of this Order. DOER argues that price cap regulation is intended to divorce the relationship between cost and rates, and that utilities implementing PBR receive the opportunity to share in the benefits arising from PBR in exchange for increasing their efficiency (DOER Brief at 6). DOER contends that the Company's planned implementation date would provide shareholders with immediate benefits that would have occurred under

traditional ratemaking, with no additional risks associated with the greater revenues (id.). Conversely, DOER argues that the Company's customers would be left worse off by virtue of paying increased rates without realizing the benefits of PBR (id.). DOER suggests that if the Department approves the Company's proposal, then the Department should consider incorporating an SQI penalty based on 1995 performance (id. at 7 n.3).

3. The Company

Boston Gas asserts that its price cap implementation date is consistent with the theory underlying PBR (Company Brief at 90). Boston Gas maintains that its cost of service portion of this proceeding is not a traditional rate case, but constitutes a transitional filing that recognizes the Company's move towards a PBR environment (id. at 88). The Company argues that it has excluded from its filing those wage and salary increases scheduled to take effect during 1997, as well as its inflation allowance for 1997, because these adjustments will be captured by the rate indexing mechanism found in PBR (id. at 89, citing Exh. BGC-38, at 10). Using this analysis, Boston Gas contends that it included its 1996 non-revenue producing additions in rate base, because the Company will not recoup the cost of these investments under the new price cap rates (id. at 89).

The Company further argues that its cost of service adjustments were designed to prevent overlapping these costs with those that would be allowed under the price cap mechanism (id. at 89-90). At the same time, Boston Gas maintains that it conformed to Department precedent in its direct filing, with particular focus on its overall employee compensation package, its 1993 through 1995 rate base additions, and QUEST (id. at 90-91).

Concerning its request that the new rates authorized by this Order not be prorated, Boston Gas argues that the one-month delay in its rate filing to provide various stakeholders

the opportunity to comment on the proposal was very constructive, and resulted in significant modifications to the originally-intended filing (id. at 155). The Company contends that in recognition of these efforts, it should be allowed to apply the increase granted herein effective with volumes billed on and after December 1, 1996 (id. at 155-156). In support of its request, Boston Gas cites its 1975 rate case as precedent for such treatment (id. at 156, citing Boston Gas Company, D.P.U. 18264-A (1975)).

C. Analysis and Findings

1. Determination of Initial Rates

With respect to the Company's inclusion of FAS 106-related adjustments, the Department has included in cost of service an appropriate level of FAS 106 expenses. Section IV.K.3, above. Therefore, a concordant adjustment to the Company's price cap revenue computation is necessary to avoid double-counting these expenses. Accordingly, the Department has eliminated Boston Gas's FAS 106 adjustments as contained in Exhibit BGC-6.

With respect to the exclusion of CGAC-related items from the Company's monopoly distribution service revenues, the Department finds that the Company appropriately has excluded its gas and gas acquisition-related costs from its monopoly distribution service revenue. D.P.U. 93-60, at 280-281. Accordingly, the Company's proposed adjustment is approved.

With respect to the Company's service to Trigen Boston, Wellesley College, MATEP, Brandeis University, and BECo, sales to these customers are being made under the terms of special contracts which are treated for ratemaking purposes as an offset to firm revenue requirements, consistent with the Department's requirements in D.P.U. 90-17/18/55 and

Colonial Gas Company, D.P.U. 90-210 (1990).[154] The Department finds that Boston Gas has treated these contract revenues in the appropriate manner.[155] Accordingly, these contracts shall be excluded from the calculation of the Company's monopoly distribution service revenue requirement.

The Department has addressed the Company's competitive services in Section XI.C.3, above. As noted, the Department has accepted the Company's proposed treatment of its D.P.U. 92-259 contracts and VNG service as elements of its competitive basket. Accordingly, these revenues shall be excluded from the calculation of the Company's monopoly distribution service revenue requirement.

Turning to Boston Gas's proposed treatment of its IT service, the Department has rejected the Company's proposed buyout in Section IX.A.3, above. Margins associated with IT service shall be flowed back to firm customers through the LDAC, consistent with our findings in Section VII.B, above. Consistent with our findings therein, the Department finds that IT service shall be excluded from the calculation of the Company's monopoly distribution service revenue requirement.

With respect to the Company's proposal to implement the first price cap-based increase effective upon the date of this Order, the Department is unpersuaded that the nature of Boston Gas's filing warrants applying the first price cap price increase in December 1996. One of the purposes of this proceeding is to establish an appropriate "cast off" point for the

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154 In D.P.U. 90-17/18/55, the Department approved the Company's proposed treatment of revenues from two cogeneration contracts as offsets against firm revenue requirements. D.P.U. 90-17/18/55 at 155, 191.

155 See, e.g., Department Letter Orders to Boston Gas dated June 7, 1991, April 16, 1993 and August 19, 1993.

Company's price cap mechanism. To that end, the investigation of the Company's cost of service conducted in this proceeding involved an extensive review of the record, with numerous adjustments where found appropriate.

Addressing the Company's expressed concerns about overlapping cost of service regulation and incentive regulation, the Department has evaluated the Company's payroll and inflation allowance components in its base rate request, and made adjustments where appropriate. See Sections IV.A.2.b and IV.T.2, above. The Department finds that Boston Gas's proposal to apply its price cap inflation factor for 1996 overlaps with both the specific adjustments made to cost of service and the residual O&M inflation allowance allowed herein.[156] Accordingly, the Department rejects the Company's proposal to implement its first increase under price cap regulation on December 1, 1996.

Based on the foregoing analysis, the Department finds that the revenue requirement approved in this proceeding is $635,551,110.[157] The removal of $376,427,430 in CGAC-related items produces a revised distribution cost of service of $259,123,680. The Department has removed an additional $9,104,256 for special contract revenues and competitive services, thereby producing a monopoly distribution service revenue requirement for purposes of the price cap application of $250,019,424. Accordingly, the Department finds that the Company's monopoly distribution service revenue requirement is $250,019,424.

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156 The Company's inflation allowance calculations submitted in its direct case provided for inflation through the end of 1996 (Exh. BGC-2, at 35).

157 This figure is net of the roll-in of local P&S costs and gas-related bad debt into the CGAC.

2. Effective Date

The implementation of rate increases by gas, electric, and water utilities is subject to the provisions of G.L. c. 164, § 94, which reads in pertinent part:

> Such rates, prices and charges shall apply to the consumption shown by meter readings made after the effective date of such rates, prices and charges, unless the [D]epartment otherwise orders.

Although G.L. c. 164, § 94 permits the Department to place a general rate increase into effect on a different basis, the Department's long-standing policy has been that general rate increases become effective with consumption on and after the date of the order granting the increase. In order for a company to implement an increase on some basis other than consumption, a company must present a compelling reason on the record. See, e.g., Dover Water Company, D.P.U. 504/505, at 5 n.1 (1981) (utility allowed to apply stipulated rate increase to water consumed before approval date because of severe financial difficulties).

According to Boston Gas, it based its proposed implementation date on its decision to defer its filing so that potential intervenors would have the opportunity to review its filing prior to its submittal to the Department. While we commend the Company for its efforts to inform parties about the nature of its case, Boston Gas has presented no compelling reason not to prorate bills, beyond what appears to be some sense of quid pro quo. The Department finds that the facts presented in D.P.U. 18264-A are distinguishable from the instant case.[158]

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158 In D.P.U. 18264-A, the Department allowed the Company to implement a rate increase for its Lynn, Mystic Valley, and North Shore Division customers on an interim basis subject to refund. The Company filed for that increase to recover a revenue deficiency that had already been found to exist over and above the requested amount sought in Boston Gas Company, D.P.U. 17885 (1974). The Department's Order in D.P.U. 17885 had been decided one month prior to the Company's request for interim rates in D.P.U. 18264-A. D.P.U. 18264-A at 5; D.P.U. 17885, at 8.

The Department finds that Boston Gas has presented insufficient reasons to justify a departure from our long-standing policy. Accordingly, the Company's request to bill the rates approved herein effective with billings on and after the date of this Order is denied. Boston Gas is hereby directed to apply the approved rates to consumption on and after the date of this Order.

XIV. TRANSPORTATION TERMS AND CONDITIONS

A. The Company's Proposal

Boston Gas proposed Terms and Conditions ("T&C") for the following four new types of services: (1) Optional Transportation Service; (2) Optional Transportation Receipt Service; (3) General Transportation Service; and (4) General Transportation Receipt Service (Exhs. BGC-67; BGC-69; BGC-73; BGC-74). The Company's proposed T&C for General or Optional Receipt Service would apply to suppliers (Exhs. BGC-73, BGC-74). The T&C for General or Optional Transportation Service would apply to customers taking transportation service (Exhs. BGC-67, BGC-69). Boston Gas stated that based on its experience with firm transportation, changes are necessary to its current T&C for Firm Transportation (Exh. BGC-66, at 4). Also, the Company submitted an Interruptible Transportation ("IT") Agreement (Exh. BGC-71).

The Company indicated that the primary differences between the T&C for General Service Tariffs and the Optional Service Tariffs are in the nominating and balancing sections, and also in the requirement that Optional Tariff customers have a remote meter reading device installed (Exh. BGC-66, at 11). Under the T&C for the Company's Optional Service, a supplier must nominate, within certain tolerances, an amount of gas that matches the daily use of its customers (id.). Under this service, customers or their suppliers will

have to balance their load (id.) Suppliers, under the Company's General service, will be required to nominate gas in quantities equivalent to the sum of the average daily use of their customers (id. at 5). Under this service, suppliers will be assessed a monthly balancing charge which is intended to allow the Company to recover the cost of managing their daily load swings (id.).

According to Boston Gas, some of the proposed revisions are based upon the Company's perception that its existing telemetering and balancing requirements may pose barriers to entry for many of its C&I customers (Exh. BGC-66, at 4). The Company stated that it based its proposal on the structure of the T&C of Public Service Gas and Electric of New Jersey (id.).

1. Optional Services

a. Introduction

The proposed T&C for Optional Transportation Service and Optional Receipt Service would apply to those customers and their suppliers who qualify for rate schedules G-41, G-42, G-43, G-44, G-51, G-52, G-53, G-54, G-61, G-62, and G-63 (Exhs. BGC-69, at 1; BGC-74, at 1). The same T&C would apply to customers taking service under the Company's IT agreement (id.).

b. Optional Transportation Service

Under the Company's proposal, a customer must (1) submit a request for transportation service for approval by the Company, (2) submit an executed contract with a supplier, (3) have remote metering equipment meeting Company specifications, and (4) supply any security deposit required by the Company in accordance with the T&C for gas service (Exh. BGC-67, at 2). A customer may elect to act as its own supplier provided that

the customer meets all the requirements of the T&C of Optional Transportation Receipt Service (id.).

According to the Company's proposal, an optional transportation service agreement must be executed prior to the tenth day of the month for deliveries to begin on the first day of the following month (id. at 3). The Company proposed an administrative charge of $50.00 to be assessed each time a customer elects to change suppliers (id.). Further, a customer cannot change its election between General Transportation Service and Optional Transportation Service more than once a year (id.). Finally, G-45, and G-55 customers would be ineligible for IT for a period of one year for the load that qualifies under rate schedules G-45 or G-55 (id. at 4).

The Company's proposal regarding force majeure, includes both upstream and downstream pipelines (Exh. BGC-67 at 7). In particular, the Company's proposed T&C provide that:

> "If the Company is unable to render the firm transportation service contemplated by these Terms and Conditions as a result of a Force Majeure, and such inability continues for a period of 30 days, Customer may provide written notice to Company of its desire to terminate its Firm Transportation Agreement at the expiration of 30 days from Company's receipt of such notice (but no sooner than 60 days following the outset of the Force Majeure). If Company has not restored service to Customer at the end of the notice period, Customer's Firm Transportation Agreement will terminate and both parties will be released from further performance thereunder, except for obligations to pay sums due and owing as of the date of termination."

(id.)

The Company's proposed T&C for optional transportation service also include general provisions regarding quality of gas, nominations, billing and meter registration, title and possession of gas, taxes, and curtailment (See Exh. BGC-67, at 3-6).

c. Optional Transportation Receipt Service

The proposed T&C for Optional Transportation Receipt Service cover areas including requirements of service, quality and condition of gas, nominations and scheduling of service, determination of receipts, balancing and balancing penalties, billing and payment, taxes, force majeure, curtailment, and capacity assignment (See Exh. BGC-74).

As part of the proposed T&C, the Company provided a set of definitions including "critical day" and "Daily Index" (id. at 2). A critical day may be declared by Boston Gas when unusual operating conditions may jeopardize the operation of the Company's distribution system (id.). The Daily Index is the midpoint of the range of prices for deliveries into Algonquin's system as published by Gas Daily (id.). In the peak season, this range would represent the Company's weighted average cost of transportation including fuel, calculated at 100 percent load factor on the pipelines serving Boston Gas (id.). In the off-peak season, this range would represent the average, including fuel, of the maximum and minimum IT rates on the same pipelines (id.). In addition, the Company retains the right to "establish reasonable and non-discriminatory standards for Suppliers" (id. at 3).

Regarding the Company's proposed requirements of service, a supplier must complete an application for participation, provide financial information, and post financial security as described below (id. at 3). In addition, a supplier must be and continue to be an approved bidder on the upstream pipelines and underground storage facilities on which the Company will assign capacity (id.). At the Company's request, a supplier must provide the Company, on a confidential basis, audited financial statements for the previous three years, appropriate trade and banking references, and a current credit report from a reputable reporting firm (id. at 4). The Company indicated that it would review a supplier's financial position

periodically. If the Company determined that financial security is necessary to ensure the performance of a supplier's obligations, the Company would require the supplier to maintain a cash deposit, a surety bond, an irrevocable letter of credit at a Company-approved bank of the supplier's choosing, or such other financial instrument as the Company might require (id.). The Company proposed that initially, the amount of such security instrument would equal the product of (1) the supplier's estimated maximum delivery obligation, expressed in MMBtu, and (2) $150.00 (id.). If the value of the security falls below the product of (1) the supplier's estimated maximum delivery obligation, expressed in MMBtu, and (2) $100.00, then Boston Gas Company would require the supplier to increase the value of the security instrument to the original level (id.). Such a security instrument would be used to satisfy Company claims in the event the supplier defaults (id.). The Company proposed that suppliers serving IT customers would be exempt from the financial security requirement (id.).

Boston Gas proposed that the quality and condition of gas delivered to the Company should conform to the gas quality standards of the delivering pipeline, should have a Btu content between 1,100 Btus and 960 Btus per cubic foot, and should be at pressure sufficient to enter the Company's distribution system without requiring Boston Gas to adjust its normal operating pressures (id. at 5). The Company may commingle the gas tendered by a supplier with other natural gas, vaporized LNG, and propane-air vapor (id.). Pursuant to Boston Gas's proposal, suppliers are expected to have good title, free of all liens, encumbrances and claims, to all gas delivered to the Company (id.).

Regarding nominations and scheduling, suppliers would be responsible for scheduling and delivering on every day an amount of gas that equals their customers's consumption for

that day (id.). The Company's proposal allows for first of the month nominations, as well as subsequent nominations (id. at 6). In the event there is a discrepancy between the volume nominated to Boston Gas by the supplier and the volume confirmed by the pipeline, the Company would confirm the lower volume (id.).

Boston Gas would assess a Company-use and unaccounted-for gas quantity against receipts, to be adjusted annually (id.). Boston Gas initially proposed to set the retention percentage at 2.5 percent (Exh. BGC-75, at 27). The Company indicated that it developed the company-use and unaccounted-for gas retention percentage based on a five-year average (id.; Exh. BGC-86). Boston Gas then agreed to an initial unaccounted for retention factor of 1.25 percent for third-party gas deliveries that would be reconciled and adjusted annually for a twelve month period ending June 30 of each year[159] (Company Brief at 149).

Regarding balancing, the Company proposed that suppliers balance their receipts with their customers's consumption at designated points (Exh. BGC-74, at 6). For each day that the delivery pipeline has not limited the Company to point-specific balancing, a supplier could balance its customers's receipts on a daily and monthly basis (id.). During the off-peak season, the Company would require a supplier to balance receipts and customer consumption within a 15 percent bandwidth (id. at 7). The Company would charge suppliers 0.1 times the Daily Index for differences exceeding this bandwidth (id.). During the peak season, suppliers would be required to balance their customers's aggregate

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159 In the Company's last rate case, the Department directed Boston Gas to conduct a study that breaks down its unaccounted-for gas into cost components, and identifies and explains the factors that cause those losses. D.P.U. 93-60, at 477. According to the study which was performed by Stone and Webster, the unaccounted-for-gas, on a physical basis, was 1.25 percent for the year ending June 30, 1995 (See Exh. DPU-218).

consumption and scheduled receipts with a ten percent tolerance (id.). For differences exceeding this tolerance, the Company would charge the supplier 0.5 times the Daily Index (id.).

In the event of an under-delivery during a critical day, the Company proposed to charge a supplier five times the Daily Index for customers's aggregate consumption on a delivering pipeline that exceeds 105 percent of a supplier's aggregate receipts on the same delivering pipeline (id.). A supplier would be charged 0.1 times the Daily Index for differences between aggregate receipts on a delivering pipeline and customers's aggregate consumption that are less than 80 percent (id.). In the event of an over-delivery during a critical day, a supplier would be charged 0.1 times the Daily Index for customers's aggregate consumption that exceeds 120 percent of the supplier's aggregate receipts on the same delivering pipeline (id.). Under the Company's proposal a supplier would be charged five times the Daily Index for differences between aggregate receipts on a delivering pipeline and customers's aggregate consumption on the same pipeline that are less than 95 percent of a supplier's aggregate receipts on the same delivering pipeline (id.).

Regarding monthly balancing, the Company proposed that a supplier must maintain total monthly receipts within a reasonable tolerance of total monthly consumption (id.). Any differences would be cashed out based on the following schedule:

Imbalance Tier	Over-Deliveries	Under-Deliveries
0% ≤ 5%	The average of the daily indices for the relevant month, but not to exceed the Daily Index for the first day of the month.	The highest average of seven consecutive daily indices for the relevant month.
>5% ≤ 10%	.85 times the above stated rate.	1.15 times the above stated rate.
>10% ≤ 15%	.60 times the above stated rate.	1.4 times the above stated rate.
>15 %	.25 times the above stated rate.	1.75 times the above stated rate.

Boston Gas would permit suppliers who have accumulated imbalances within a month to nominate to reconcile such imbalances, subject to the Company's approval (id. at 8). The Company's T&C provide for trading of imbalances on a daily and monthly basis (id.).

Finally, the Company has proposed the method by which Boston Gas would make a mandatory assignment of its upstream capacity including Canadian supplies (id. at 10).[160]

2. General Service

The Company's proposed T&C for General Transportation Service and General Transportation Receipt Service would apply to customers, and their suppliers, qualifying for C&I rates G-41, G-42, G-43, G-44, G-51, G-52, G-53, G-54, G-61, G-62, and G-63, and who would purchase gas supplies in any manner other than from the Company's CGAC for transportation by the Company (Exhs. BGC-67, at 1, BGC-73, at 1).

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160 The Department addresses the Company's proposal regarding the assignment of capacity in Section X, above.

a. General Transportation Service

In order to receive service under this proposed tariff, Boston Gas would require customers to (1) submit for approval by the Company a request for Transportation Service, (2) submit a contract with a supplier, and (3) supply any security deposit required by the Company (id. at 3). A firm general transportation agreement must be executed prior to the tenth day of the month for deliveries to commence on the first day of the following month (id.). The Company would charge a customer an administrative fee[161] of $50.00 each time a customer elected to change suppliers (id. at 4). According to the proposed T&C, the Company could commingle the gas tendered by the supplier at the designated receipt points, with other gas, vaporized liquified natural gas, and propane air vapor, and deliver a mix of gas to the customer at the delivery point (id.).

The Company's T&C further state that in the event a supplier defaults, Boston Gas would provide an interim sales service ("ISS"), using its best efforts to meet the gas supply requirements of the customer (id. at 5). According to the proposed T&C the Company would be obligated to provide this service only until the earlier of: (1) customer's selection of another qualified supplier; or (2) the last day of the month (id.). The Company proposed that while it provides ISS, customers would be assessed a charge of 1.5 times the Daily Index or the Company's GAF in effect at the time, whichever is greater (id.). The Company also indicated that at present any customers converting from transportation to sales would not impose additional costs (Tr. 9 at 77, 78).

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161 The Company asserts that this fee is intended to recover the costs of administrative tasks that are caused by changing suppliers (Exh. DOER-34). The Company also indicates that the fee is intended to ensure that customers would change suppliers with due consideration (id.). Finally, the Company indicated that it estimated the level of the fee (id.; Tr. 5, at 98).

b. General Transportation Receipt Service

Most of the T&C applicable to the general transportation receipt service, are similar to those proposed for the optional transportation receipt service, with the exceptions set forth below.

Under the Company's proposed T&C for general transportation receipt service, a supplier would be obligated to schedule and deliver the adjusted target volume ("ATV")[162] to the designated receipt points on every day (Exh. BGC-73, at 5). In addition, the Company would assess a company-use and unaccounted-for quantity which would be adjusted annually (id. at 7).

Boston Gas proposed to manage the customers's swing and all hourly, daily, and monthly balancing using the Company's local peaking resources and underground storage (Exh. BGC-66, at 7). The Company stated that it would recover the cost of this service through a balancing charge (id.). The Company initially proposed a balancing charge of $0.2649 per MMBtu (Exh. BGC-75, at 27). Boston Gas indicated that this charge would change semiannually at the time of the implementation of the Company's CGAC (id.).

Under the Company's proposed balancing provisions, for each day that the delivering pipeline has not limited the Company to point-specific balancing, any difference between a supplier's ATV on a delivering pipeline and the receipts on that same delivering pipeline would be cashed out by the Company as described below.

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162 In order to calculate the ATV, Boston Gas would sum the daily contract quantities for a supplier's pool on each delivering pipeline, add the Company-use and unaccounted-for quantity and adjust this total by any imbalances that occurred for the same pool in the previous period (Exh..BGC-73, at 6). The sum of these volumes would be the ATV for each delivering pipeline (id.).

During the off-peak season, receipts less than the ATV, would be cashed out at 1.1 times the Daily Index (Exh. BGC-73, at 7). For deliveries greater than the ATV, the difference would be cashed out at 0.8 times the Daily Index (id.). During the peak season receipts less than the ATV but greater than or equal to 95 percent of the ATV would be cashed out at 1.1 times the Daily Index (id.). For receipts less than 95 percent of the ATV, the first five percent difference would be cashed out at 1.1 times the Daily Index, and the remaining difference would be cashed out at 2.0 times the Daily Index (id.). For receipts greater than the ATV, the difference would be cashed out at 0.8 times the Daily Index (id.).

Under the Company's proposal, the Company would determine if the critical day will be aggravated by an under-delivery or by an over-delivery, and so notify suppliers when a critical day is declared (id.). For critical days aggravated by under-deliveries, the difference between receipts and the ATV would be cashed out at 5 times the Daily Index (id.). Receipts greater than the ATV but less than or equal to 125 percent of the ATV, would be cashed out at the Daily Index (id.). For receipts in excess of 125 percent of the ATV, the first 25 percent difference would be cashed out at the Daily Index, and the remaining difference would be cashed out at 0.8 times the Daily Index (id.). For critical days aggravated by over-deliveries, receipts greater than the ATV would be cashed out at 0.4 times the Daily Index (id.). Receipts less than the ATV but greater than or equal to 75 percent of the ATV, the difference would be cashed out at the Daily Index (id.). For receipts less than 75 percent of the ATV, the first 25 percent difference would be cashed out at the Daily Index and the remaining difference would be cashed out at 1.1 times the Daily Index (id.). In the event the delivering pipeline requires the Company to balance on a point-specific basis, a supplier must balance at each designated receipt point (id. at 8).

The Company would flow through to suppliers any pipeline imbalance penalty charges attributable to the supplier (id.). If, in any month, a supplier under-delivers an amount equal to or greater than five times the total ATV, it would be ineligible to nominate gas for the remainder of the month (id.). The supplier could be reinstated on the first day of the following month, provided the supplier posted security equal to two times the security required (id.). If such supplier is declared ineligible to nominate gas a second time within twelve months of the first offense, the Company would disqualify the supplier from service under these T&C for one full year from the time of the second disqualification (id.).

The Company proposes that in the event the Company has declared a critical day, the Company would have the right to issue an operational flow order ("OFO"), by which the Company could instruct suppliers to take actions as conditions require (id.). An OFO could be issued on a pipeline or point-specific basis (id.). Finally, the Company proposed the method by which it would assign upstream capacity, including Canadian supplies (id. at 11).

The Company indicated that the proposed balancing service is designed to recover the costs associated with managing the daily load variations within a month (Exh. BGC-75, at 23). Under the Company's proposed general transportation receipt service, gas brokers would be required to deliver to the city gate an average daily contract quantity ("DCQ") which is the sum of their customers's average daily use (id. at 23, 24). Boston Gas proposed to balance the swing between the average daily use and the actual daily use (id. at 24).

In order to develop the balancing charge, the Company first determined the maximum daily and annual volumes required to provide balancing service (id.). Boston Gas used normal throughput volumes for test year 1995 and calculated a system-wide DCQ for each month by averaging the daily sendout volumes in each month (id.). The DCQ was then

subtracted from the actual sendout volume to calculate the balancing or swing requirement necessary to meet customer demand on each day (id. at 24-25). Balancing needs were determined by looking at the days when actual sendout exceeded the DCQ (id. at 25). Next, the Company allocated costs based on three cost categories (id.). The first category, Fixed Costs - Production and Transportation[163] would be recovered based on the percentage of the Company's peak daily balancing requirement to the capacity of each resource (id.). The second category, Fixed Costs-Capacity, includes costs associated with pipeline storage capacity charges and LNG storage costs (id.). These costs would be recovered based on annual storage balancing requirements (id. at 26). The third category, Variable Costs, represents the difference in costs between the commodity cost of LNG used to provide a portion of the swing and the cost of the commodity resources returned as replacement balancing gas (id.). The Company stated that it would be using storage and LNG assets to balance its system and take the swings between the DCQs and actual takes by the customers (id.). The Company claims that since LNG is more expensive than pipeline gas and is more difficult to replace, the cost difference must be recognized in the rate (id.). Finally, to calculate the per unit rate, the Company divided the total allocated balancing cost by the annual CGAC throughput (id.). Boston Gas indicated that the balancing charge will change semi-annually to coincide with the Company's CGAC filings (id. at 27).

3. Interruptible Transportation

The Company's proposed T&C for IT address areas such as interruption of service, public regulation and termination, metering, and rate (Exh. BGC-71).

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[163] Costs allocated to this category include short haul transportation and LNG vaporization capacity (Exh. BGC-75, at 25).

B. Positions of the Parties[164]

1. The Attorney General

The Attorney General argues that Boston Gas's proposal regarding the Company's proposed credit worthiness review is designed to protect Boston Gas only (Attorney General Brief at 94). The Attorney General proposes that the Department direct Boston Gas to require that marketers maintain a performance bond in the amount of $1,000,000 (id.). According to the Attorney General, the Company would use this bond to secure a marketer's performance under its agreement with customers, for failure to deliver gas at a particular price and for failure to maintain a customer's pro rata share of interstate pipeline capacity (id.).

The Attorney General further argues that the Department should direct the Company to include the following language in the Company's tariffed marketer agreement:

> The [XYZ Marketing Co.], Inc. acknowledges and agrees as a condition precedent and a continuing obligation, to comply with all applicable state and federal consumer protection and truth in advertising statutes and regulations, including but not limited to the Massachusetts Consumer Protection Act, G.L. c. 93A; the Attorney General's Regulation promulgated pursuant to the Massachusetts Consumer Protection Act, including 940 CMR §§ 3.00 et seq. (general regulations), and 940 CMR §§ 6.00 et seq. (retail advertising regulations; the Telemarketing and Consumer Fraud and Abuse Prevention Act, 15 U.S.C. sections 6101-6106; the Federal Trade Commission's Telemarketing Sales Rule, 16 C.F.R. Part 310 and, section 310.3(a); and G.L. c. 159, § 19E.

(id. at 95-96). The Attorney General maintains that incorporation of this language would compel marketers to comply with certain existing consumer protection statutes (id. at 95).

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164 Some participants argued on brief about issues relating to the assignment of Company's D.P.U. 92-259 contracts to AllEnergy, and standards of conduct between an LDC and its affiliates. As indicated in Section I, supra, the Department is investigating these matters in D.P.U. 96-44 and D.P.U. 96-66, and, therefore will not address such comments in this section.

Finally, the Attorney General contends that, at a minimum, the Company's firm customers must be protected from the impact of market failures during the transition period (id. at 96). The Attorney General argues that the Department should reject the Company's proposal related to ISS and direct the Company to provide this service to customers at a weighted index price based upon the Company's most recent experience, or at the Company's CGAC (id. at 96-97).

2. DOER

DOER argues that the Company's proposed ISS should be modified to protect core customers (DOER Brief at 87). In particular, DOER contends that Boston Gas should not be permitted to charge customers a rate that is higher than the cost of providing ISS during the interim period (id.). DOER argues that because customers would not select ISS, but rather receive that service by default, the rate that they would be charged should be fair (id.).

Regarding the retention factor proposal by the Company, DOER contends that Boston Gas should adjust this factor to 1.25 percent (id. at 88). DOER argues that more recent analyses presented by the Company indicate that, on a physical basis as of June 30, 1995, the Company use and unaccounted-for factor is 1.54 percent in total, and 1.25 percent if company use is excluded (id., citing RR-TEC-2 (rev.); RR-TEC-3).

DOER argues that the Company's proposed allocation of the costs of telemetry equipment to all G-45 and G-55 customers is inappropriate (id. at 89). DOER contends that, under the Company's proposal, customers who already have paid for their own telemetry equipment would also bear a portion of the costs associated with the installation of this equipment for other customers (id.). DOER suggests that the Company could consider a lump sum payment of the equipment costs pro-rated on a 14 year life instead of a billing

credit (id., citing RR-DPU-84). DOER advocates that the Department order Boston Gas to develop an appropriate mechanism to reimburse the existing G-45 and G-55 transportation customers, via either a credit or lump sum payment (id.).

Finally, DOER argues that in order to allow customers to obtain the full benefits of a competitive retail market, the Company should permit customers to use balancing services provided by entities other than Boston Gas (Exh. DOER-71, at 23). According to DOER, the Company should develop a consumption algorithm to calculate daily consumption in lieu of an actual meter reading (id.). Suppliers would use this algorithm to calculate daily nominations and estimate balancing requirements (id.).

3. TEC

TEC argues that many of the existing customers served under rates G-45 and G-55 have already paid for the installation of telemetry equipment (TEC Brief at 7). As a result, TEC advocates that the Department direct Boston Gas to unbundle the cost of the telemetry equipment which the Company has proposed to include in the customer charge (id.).

TEC indicates its opposition to any daily balancing penalties, unless the actions of a customer or supplier cause the Company to incur penalties on the interstate pipeline or cause the Company to incur additional costs on its system which otherwise would be charged to sales customers (id. at 17). TEC argues that any imbalances that do not cause the Company to incur balancing penalties on the interstate pipelines or require the Company to dispatch propane or LNG should be waived (id.). Finally, TEC argues that any daily imbalance penalties should be imposed only after customers have had the opportunity to trade their imbalances (id. at 18). TEC supports the monthly cashout scale for imbalances proposed by US Gypsum (id., citing Exh. USGC-1).

TEC also argues that the balancing charge for General Transportation Service is excessive (id.). TEC points out that the Company's proposed charge is based on the assumption that all swing volume would be met by LNG or propane capacity (id. at 19). TEC asserts that balancing could be provided through the use of pipeline "no-notice" service or other pipeline flexibility as to hourly or daily quantities (id.). Finally, TEC claims that the balancing charge should be calculated on a seasonal basis and in a way that considers a portion of all facilities that will be used (id.). TEC suggests that the only method which approximates its proposal results in a balancing charge of $0.2242 per MMBtu (id., citing RR-DPU-47). TEC proposes that the Department approve the balancing charge of $0.2242 per MMBtu (TEC Reply Brief at 9).

Regarding the Company's proposed ISS, TEC argues that there is no reason to charge customers a rate that is 50 percent higher than the Daily Index (TEC Brief at 19, 20). Further, TEC proposes that the ISS also be made available to Optional Transportation Service customers (id. at 20).

TEC proposes that Boston Gas codify its policy on combined metering (id.). In particular, TEC suggests that Boston Gas be required to include the following language in its proposed T&C:

> A customer may request combined billing of multiple meters on contiguous property and shall be classified as a single customer under any service classification or rate. A customer may request the installation of single metering of multiple meters on contiguous property so long as the customer pays the reasonable cost to combine the usage on a single meter. In either case, the Company shall continue to own, maintain, test and operate the gas piping and related equipment in accordance with the Massachusetts code.

Id. at 20, 21.

Finally, TEC advocates a retention factor of 1.25 percent (id. at 24). TEC asserts that Boston Gas has the ability to reduce losses by improved maintenance of its distribution system and, therefore, should not be allowed to retain the total savings from any improvements (id.). TEC recommends that in order to ensure that Boston Gas does not shift the operating risk from the Company to the customers, the retention factor, if adjusted annually, should only be adjusted downwards (TEC Reply Brief at 2).

4. Berkshire

Berkshire notes that the credit checks imposed by the pipeline companies are adequate to ensure the credit worthiness of marketers (Berkshire Reply Brief at 4). Berkshire, therefore, concludes that additional measures to ensure credit worthiness would be both redundant and an unnecessary burden for all involved (id.).

5. AIM

AIM argues that suppliers should be required to provide financial security which customers can access in the event their supplier defaults or the customer incurs interruption penalties (AIM Brief at 21). Regarding the Company's proposed ISS, AIM argues that there is no justification for the Company's proposal (id. at 22). AIM proposes that ISS should be provided at the Company's GAF or the index rate, whichever is lower (id.).

6. US Gypsum

US Gypsum argues that the Company's current balancing penalty regime is unreasonable and should be modified (USGC Brief at 12). US Gypsum offers the following modifications: (1) daily penalties should be eliminated except when the Company's system is threatened by extreme weather conditions or by excessive system imbalances; (2) imbalances should be corrected on a monthly basis, using a cashout system; (3) monthly cashout

assessments should apply only after the customer has been given the opportunity to trade imbalances; (4) Boston Gas should not be allowed to retain or profit from penalty revenues; and (5) Boston Gas should not be permitted to impede efforts by shippers to arrange for balancing upstream of the Company's system (id. at 13, 14). US Gypsum concludes that the balancing penalties as proposed by Boston Gas are unnecessarily harsh (USGC Reply Brief at 4).

7. Enron

Enron argues that the Company's proposal to designate the delivery points into the Boston Gas system available to suppliers and transportation customers may lead to the assignment of more expensive options to transportation customers (Exh. ECT-1, at 3). Enron asserts that ideally suppliers should have the option to select their own delivery points into the Boston Gas system, subject to system constraints (id. at 4).

Enron maintains that the proposed fee for changing suppliers creates a barrier to entry (id.). Enron notes that consumers would not be willing to pay this fee, and because of the narrow margins, marketers would be unwilling to absorb this charge (id.).

Enron contends that the Company's proposal does not provide adequate aggregation opportunities for suppliers (id.). Enron states that the Company's proposal limits aggregation to individual delivery points into its system (id.). Enron argues that just as Boston Gas currently aggregates across its system, non-utility suppliers should be allowed to aggregate gas delivered to any and all delivery points (id.).

Finally, Enron notes that the Company's proposal regarding agent assignment should be modified in order to allow a supplier to act as an agent (id. at 5). Enron asserts that a supplier should be able to inform Boston Gas that the supplier has been appointed agent for a

customer and provide written or voice verification of such appointment, if a verification is required (id.).

8. TMG

TMG argues that Boston Gas should be required to allow General Transportation customers to secure balancing services from third parties and allow self-balancing without the need for installation of telemeters (TMG Brief at 16). TMG agrees that this change to the Company's proposed T&C would require that customers and marketers have access to various on- and off-system storage and peaking assets necessary to provide self-balancing (id.). TMG argues that it would be more efficient to meter a small number of deliveries at the city-gate instead of thousands of burner-tips (id.). TMG notes that such third-party balancing would not require the use of telemeters, eliminating a barrier to entry for smaller customers (id. at 16, 17). TMG stated its support of a "no harm no foul" approach regarding daily balancing, especially given the existence of monthly penalties and charges (TMG Reply Brief at 6, citing TEC Brief at 17).

TMG disagrees with Distrigas's proposed balancing charge for the general transportation service (id. at 6, citing Distrigas Brief at 8). TMG asserts that the proposed balancing charge is excessive and not fully tied to the cost of the actual facilities used to provide this service (id.). TMG maintains that in addition to LNG and propane assets, the Company will utilize less expensive resources such as upstream storage and no-notice service, and concludes that the balancing charge proposed by Distrigas should be rejected (id.).

TMG suggests modifications to the Company's proposal regarding the credit-worthiness and financial information requirements to eliminate undue discretion and to

reflect the requirements of the upstream pipelines (TMG Brief at 22). TMG maintains that suppliers who have satisfied the pipeline credit worthiness test should not be required to provide security deposits or letters of credit to Boston Gas (id. at 23). TMG concedes that suppliers who fail the pipeline credit worthiness test should be required to provide a reasonable assurance of payment, provided that it is explicitly stated in the Company's T&C (id.). TMG argues that the credit worthiness test should be applied in a non-discriminatory manner (id.). Finally, TMG argues that the credit worthiness review process should be completed within a reasonable period to allow suppliers the opportunity to enter the market without delays (id. at 24). TMG opposes the Attorney General's recommendations that marketers be required to provide a $1,000,000 bond reachable by customers and accept boilerplate language regarding compliance with existing state and federal laws (TMG Reply Brief at 4). TMG claims that the Attorney General's proposal is at best inappropriate and redundant (id.). TMG maintains that the bonding requirement is not standard industry practice and would act as a substantial barrier to entry (id.).

TMG asserts that the Company's proposed sign-up process is unworkable, leading to unnecessary costs and undue burdens on the customer (TMG Brief at 24). TMG argues that the Company's sign-up proposal is burdensome for the customer, and suggests that customers should have the right to assign an agent to secure transportation service (id. at 24-26). TMG refers to federal policies, and established processes in other industries regarding the assignment of an agent and the process for signing up for service (id. at 26-30).

TMG asserts that in order to eliminate unnecessary costs and burdens for customers converting to transportation, Boston Gas should provide marketers with the option to bill

customers directly for supply service, or both transportation and supply service (id. at 31, 32).

Regarding the proposed administrative fee paid by customers who change suppliers, TMG argues that it is not cost-justified, represents a barrier to entry, and should be removed form the Company's proposed T&C (id. at 32). Similarly, TMG argues that the proposed ISS rate is an unjustified penalty, represents a barrier to entry and should be revised to require Boston Gas to take a customer back on the ISS service at the Company's GAF or its Daily Index, whichever is lower (id. at 33).

TMG argues that Boston Gas should not retain discretion to reject a transportation request on the grounds that provision of this service may impair the Company's firm service obligations (id. at 34). Therefore, TMG argues that this clause should be removed from the Company's proposed T&C (id.). TMG also argues that Boston Gas should not have the right to develop standards for marketers, and any reference or attempt to establish "reasonable and non-discriminatory standards for suppliers" should be removed from the Company's proposed T&C (id. at 34, 35, citing Exh. BGC-68).

TMG challenges the Company's proposed retention factor (id. at 36). TMG contends that the Company's retention factor should be adjusted to 1.25 percent to reflect more recent information (id., citing RR-TEC-3).

TMG proposes that the Company amend its proposal requiring suppliers to provide information to identify supplies, on the grounds that this information may be confidential and proprietary (id. at 37). TMG argues that the proposed T&C should be further amended to allow customers to convert between optional and general transportation services more

frequently than once a year (id. at 38). TMG asserts that Boston Gas has not shown how this limitation is tied to operational constraints or supply-related constraints (id.).

TMG asserts that the proposed force majeure provisions allow Boston Gas substantial flexibility which is not warranted (id. at 39). TMG proposes two modifications to the Company's force majeure provisions. First, TMG suggests that breakage or accident to machinery or pipeline should not qualify as a force majeure event if it resulted from the Company's negligence or misconduct (id.). Second, TMG recommends that Boston Gas modify its notice provision to indicate that in the event the Company is unable to restore service to a customer in 30 days, the customer (1) is immediately relieved of any further demand charge obligation, and (2) may, at its sole option, elect not to terminate the contract by providing Boston Gas with an additional 30 days to correct the service interruption (id. at 40). TMG proposes several changes to the Company's proposal regarding curtailment on the grounds that it provides significant discretion and uncertainty (id. at 40-42).

TMG asserts that the Company's proposed one-year limitation before G-45 and G-55 customers are eligible for IT is unjustified, unduly constrains customer choice and should, therefore, be deleted (id. at 44). Finally, TMG argues that Boston Gas must modify its rate forms to clarify that the Company "is obligated to inform, with a reasonable notice period, the Customer/Supplier of any rate, or terms and conditions changes prior to filing such changes with the Department" (id. at 48).

9. Tennessee

Tennessee argues that the Company's proposed Daily Index may cause economic distortions by providing incentives for a supplier to create an imbalance on the Tennessee pipeline (Tennessee Brief at 6). Tenneco suggests that the cashout mechanism provided in

the Company's optional transportation receipt service should take into consideration prices on the Tennessee system in order to minimize any arbitrage effect (id.).

10. Distrigas

Distrigas proposes that the Company expand its definition of designated receipt point to include the Distrigas interconnection (Distrigas Brief at 2). Distrigas notes that this interconnection can be assigned as an "alternate designated receipt point" (id. at 5). Such assignment will allow Distrigas to deliver gas to that point for the customer's use in lieu of deliveries at the designated receipt point (id.).

Distrigas argues that the Company should be required to allow smaller transportation customers to acquire balancing services from parties other than Boston Gas (id.). Distrigas notes that the Company's proposal unnecessarily reduces customer choice and competition for the proposed balancing service in Boston Gas's General Service Transportation Tariff (id.). Distrigas asserts that Boston Gas is capable of providing such an option (id. at 6, citing Tr. 5, at 93; Exh. DOER-33). Distrigas concludes that there is no reason to delay implementing this proposal, which would offer customers and their suppliers more options and a better opportunity to reduce costs (id. at 6-7). Distrigas argues that implementing a sendout formula now would allow the market to develop the necessary services before the time of Boston Gas's proposed exit of the merchant function and when Boston Gas is no longer able to provide the balancing service for all of its customers (Distrigas Reply Brief at 3).

Distrigas asserts that the methodology used by Boston Gas to determine the balancing charge is flawed and reflects the cost of providing a much more limited balancing service (Distrigas Brief at 8). Distrigas proposes that the balancing charge should be developed

using allocated demand and capacity costs based on the amount of peak day and annual sendout capability that Boston Gas would have to reserve in order to meet its balancing service obligations on a design day and a design year (Exh. DOMAC-7, at 12-13). Distrigas's proposal would yield a balancing charge of $0.3786 per MMBtu (id. at 13). Therefore, Distrigas argues, the Company's balancing charge should be increased to reflect the cost of the actual services covered by that charge (Distrigas Brief at 7).

11. Texas-Ohio

Texas-Ohio supports the Company's proposed balancing charge, telemetering requirements for optional transportation service, delivery point requirements and imbalance trading rules (Exh. TOG-1, at 11-13). In addition, Texas-Ohio asserts that, based on its experience, the bandwidths for over- and under-delivery penalties and the level of those penalties are reasonable (id. at 14).

Texas-Ohio proposed that to help maintain levels of assistance to low-income heating customers, the imbalance penalties paid by marketers should be deposited in a charitable account Boston Gas would operate for the low income heating assistance (id. at 20).

12. Low-Income Intervenors

The Low-Income Intervenors support Texas Ohio's proposal that imbalance penalties be funneled into an account administered by the Company (Low-Income Intervenors Brief at 9). The Low-Income Intervenors argue that because the purpose of these penalties is not to recover actual costs Boston Gas incurs as a result of imbalances, these penalties should not accrue to the Company's shareholders (id.).

13. The Company

Regarding the assignment of an agent, Boston Gas states that it recognizes a customer's right to designate a supplier to act as its agent (Company Brief at 37). In addition, the Company indicates that it is amenable to streamlining the application process through the use of voice authorization which would allow the customer to authorize the Company to deal directly with the supplier in the application process (id.). However, the Company argues that any streamlining must afford protection for customers and preserve the effective dates for commencement of transportation service set forth in the proposed transportation tariffs (id.).

Boston Gas indicates that it intends to provide suppliers the opportunity to deliver and balance at as many points as possible along a delivering pipeline, subject to restrictions imposed by the pipelines (id., citing Exh. BGC-73, at 8; Exh. BGC-74, at 6; Tr. 5, at 182). The Company agrees with Distrigas that those customers who can be physically served from the Distrigas interconnection in Everett should be permitted to elect it as an alternate designated receipt point (id.).

The Company asserts that the development of a sendout formula as an alternative to its DCQ approach would create barriers to entry for suppliers and hamper the evolution of a competitive marketplace (id. at 38-39). Boston Gas argues that this approach would superimpose additional operating conditions on the Company and marketers (id. at 38). The Company, however, agrees that a sendout formula approach would match scheduled volumes to consumption more closely and offered, as an option, to develop a sendout formula based approach on a test or pilot basis (id. at 38-39).

The Company disagrees with US Gypsum's proposal that balancing penalties be imposed only in the event that the system is threatened (id. at 39). The Company asserts that this approach to balancing penalties is not appropriate since transportation will not be limited to only a few large customers (id.). Boston Gas notes that the purpose of penalties is to inhibit behavior that would harm an LDC's distribution system (id. at 40). The Company argues that if penalties were imposed only when the system is threatened, they cannot serve this purpose (id.).

Boston Gas accepts, with certain modifications, the proposal submitted by Texas-Ohio and supported by the Low-Income Intervenors regarding the disbursement of the balancing revenues (id.). The Company proposes to return the daily balancing penalties collected under Section 6.3 of the T&C of optional transportation service to Boston Gas customers qualifying for the Company's low income discount rate (id. at 41). All charges collected under Section 6.1 of the T&C of general transportation receipt service and Section 6.4 of the T&C of optional transportation receipt service would flow to firm sales customers through the Company's CGAC (id.).

The Company argues that it is inappropriate to calculate the balancing charge on a marginal cost basis because it is an unbundling of an existing service and would require no additional facilities (Company Reply Brief at 30).

Regarding TEC's proposal to allow only a downward adjustment to the retention factor, the Company argues that such a performance incentive would be unfair and unnecessary (id. at 31). Boston Gas asserts that it has taken steps to control losses, and that other losses are beyond the Company's control (id.). Further, the Company argues that it

must be allowed to recover the cost of gas used by the Company, and proposes to recover any such volumes through the proposed LDAF (id. at 149).

Finally, Boston Gas states that the multiplier to the index price should be eliminated for the Company's interim sales service (id.). The Company, however, argues that customers using the ISS should be charged the higher of the Company's CGAC or the Index (id. at 31, 32). The Company argues that under this revised proposal, sales customers would not be subsidizing transportation customers (id. at 32).

C. Analysis and Findings

The Company's proposed T&C for transportation present a significant departure from existing practice, in that Boston Gas developed different sets of T&C for gas suppliers and customers, detailing each party's responsibilities pursuant to a particular transportation service. The Department will address below the issues that have been raised by the intervenors in this proceeding.

1. Financial Security Requirements

The Company has proposed that suppliers must provide financial information and post financial security if required. This financial security would be a function of a supplier's commitments. The Department notes that, while a number of intervenors have argued that the Company's proposal may be redundant, they acknowledge that suppliers who fail a pipeline creditworthiness check should provide a reasonable assurance of payment.

Under the Company's current proposal, a supplier who has met the pipeline creditworthiness criteria may still be required to post a financial security. The Department finds that the credit checks currently required by pipelines would provide adequate assurance that a supplier will most likely be able to meet its financial obligations. Demanding

additional financial security from suppliers who have met the pipeline criteria may act as a barrier to entry. Consequently, the Department rejects this requirement.

The Department is aware that there may be occasions when a supplier may not have met a pipeline's creditworthiness criteria. In that case, Boston Gas would be permitted to evaluate the supplier's credit worthiness, and require some sort of financial security, if the Company deems necessary. Accordingly, the Department directs Boston Gas to amend its proposed T&C for receipt service to provide that only suppliers who have failed to meet the pipeline credit worthiness criteria would be required to post a financial security.

With respect to the Attorney General's proposal that marketers maintain a $1,000,000 performance bond, the Department finds that such a requirement would act as a barrier to entry for many potential suppliers. Accordingly, the Department declines to adopt the Attorney General's recommendation.

2. ISS

The Company's proposal to offer gas sales service to customers whose supplier has defaulted is compatible with the Department's goals of ensuring reliable service to gas users. The Company modified its initial proposal to reflect the concerns expressed by various intervenors over the need for a multiplier to the Daily Index. Because the Company has proposed to retain recall rights for all the capacity that will be assigned to suppliers, Boston Gas would not be expected to incur any additional costs or penalties related to the provision of ISS. However, the Department recognizes that, on occasion, Boston Gas may not be able to nominate additional supplies for the benefit of its ISS customers, and consequently may incur unexpected costs. In order to avoid the subsidization of transportation customers by firm sales customers, ISS customers should bear all costs associated with the delivery of ISS.

Therefore, the Department directs Boston Gas to amend its T&C so that the charge for the ISS is equal to the Company's CGAC, unless the Company incurs additional costs that are attributable to the provision of ISS. In that case, the Company will charge its ISS customers the Daily Index. In the event that Boston Gas charges the Daily Index, customers should be given the opportunity to verify the Company's charges.

3. Retention Factor

In the Company's last rate case, the Department allowed the Company to retain 3.0 percent[165] of daily deliveries to firm transportation customers to account for distribution system losses. In doing so, the Department noted that the Company was unable to determine the causative factors of its unaccounted-for gas. D.P.U. 93-60, at 476. Therefore, the Department directed the Company to present, in its next rate case, "a study that breaks down its unaccounted-for gas into cost components, and identifies and explains the factors that cause those losses." Id. at 477.

The Company's initially-proposed retention factor was based on a five-year average. The Company provided a more recent analysis using current data which indicated that for the year ending June 30, 1995, the Company use and unaccounted-for factor was 1.54 percent. The study also shows that unaccounted-for gas represents 1.25 percent of volumes, once Company use is excluded. Accordingly, the Department finds that a retention factor of 1.25 percent is reasonable and appropriate. The Department notes that the Company agrees to an unaccounted-for factor of 1.25 percent.

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165 In order to derive the retention percentage, used in that case, the Department subtracted the test year volumes of Company-use gas from the total Company-use and unaccounted-for gas. Boston Gas Company, D.P.U. 93-60, at 476.

The Company proposed to adjust the retention factor annually to reflect updated information regarding Company-use and unaccounted-for gas. The Department commends Boston Gas for its willingness to update this retention factor annually, and directs Boston Gas to do so to reflect any additional savings. The Department notes that a significant factor affecting the Company's unaccounted-for gas ratio is the age of the Company's distribution system. As Boston Gas continues to upgrade its distribution system, the Department anticipates that the unaccounted-for factor will decrease. The Department, therefore, directs the Company to amend its proposed T&C to reflect that the retention factor is capped at 1.25 percent for the duration of the Company's five-year price cap plan.

The Company has proposed to recover Company-use volumes through the LDAF. The Department notes that the record contains insufficient information to assist the Department in assessing the impact of this proposal. Consequently, the Department rejects the Company's proposal to recover Company-use volumes. After the five-year term of the price cap plan approved herein, if the Company wishes to recover Company-use volumes from transportation customers, the Company is expected to perform an analysis demonstrating the appropriateness of such proposal.

4. Alternative Balancing Services Provision

A number of intervenors have argued that the Company should allow customers to use balancing services provided by entities other than Boston Gas. The Department agrees with those parties that balancing service is an area in which competition is possible, and is likely to lead to useful service innovations that could make transportation a more viable service option over time. It appears that this is another area where there is some agreement among the parties. As noted by the parties, the Company will have to develop a consumption

formula to project daily consumption for customers, and therefore, allow suppliers to project nominations and balancing requirements. Boston Gas expressed a willingness on brief to implement third-party balancing on a pilot basis, in order to match scheduled volumes to consumption more closely. In light of the above, the Department directs the Company to develop a sendout formula-based approach on a pilot basis. We direct the Company to file a pilot program for Department approval addressing third-party balancing no later than six months from the date of the issuance of this Order.

5. Balancing Penalties; Disbursement of Penalty Revenues

Certain intervenors have argued that any balancing penalties should be imposed only if the actions of a supplier or customer cause the Company to incur penalties on the interstate pipelines, or cause the Company to incur additional costs which would otherwise be charged to sales customers. This proposal is referred to as a "no harm no foul" approach. Further, intervenors argued that daily imbalance penalties should be imposed only after customers have had the opportunity to trade imbalances.

In D.P.U. 93-60, the Department recognized that the Company must balance its system not only on a monthly basis but also on a daily and hourly basis. D.P.U. 93-60, at 478. In that Order, the Department approved the Company's proposal to impose a penalty on customers's daily overtakes, and allowed Boston Gas to include those daily overtakes in the calculation of the net cumulative monthly imbalances. Id. Under the Company's current proposal, suppliers must balance their receipts at designated points with their customers's consumption, and are permitted to exchange monthly and daily imbalances.

The Company's proposed T&C for Optional Transportation Receipt Service allow suppliers to exchange monthly and daily imbalances. The Company's proposed T&C for

General Transportation Receipt Service do not offer similar provisions. As an initial matter, the Department finds that the purpose of penalties is to inhibit behavior that would harm the LDC's distribution system, and that if penalties are imposed only when the system is threatened, these penalty provisions cannot serve this purpose. Therefore, the Department rejects the intervenors's proposal that the Company be allowed to penalize out of balance customers only in the event that they caused the Company to incur additional costs. The Department anticipates that the existence of positive and negative imbalances at the designated receipt points on a given day would minimize the impact of imbalances on the Company's overall distribution system. Accordingly, the Department directs Boston Gas to modify its proposed T&C to allow suppliers to exchange daily imbalances on a delivering pipeline, before penalties are imposed. For the same reasons, the Department directs the Company to modify its proposal regarding monthly balancing, to allow suppliers and customers to cashout imbalances before penalties are imposed.

The Department notes that the proposal to use the imbalance penalty revenues as a credit against the Company's low income accounts removes all incentives for the Company to impose undue penalties. Boston Gas proposed to deposit a portion of the balancing penalty revenue as a credit against low income accounts, with the remainder of those revenues credited to the Company's firms sales customers through the CGAC. Boston Gas, however, has not provided adequate justification for the latter part of this proposal. The Department finds that the Company's proposal to flow a portion of the balancing revenues to firm sales customers would send incorrect commodity price signals to these customers. Therefore, the Department rejects the Company's proposal to flow a portion of the balancing penalty revenues to firm sales customers through the CGAC. Instead, Boston Gas is directed to

apply all of the imbalance penalty revenues as a credit to the Company's low-income accounts.

The Department notes that the potential level of penalty revenues is uncertain at this time. Accordingly, the Company is hereby directed to file with its initial price change under the PBR a breakdown of its balancing penalty revenues by type of penalty. At that time, the Department may reexamine the treatment of those revenues.

6. Balancing Charge

Boston Gas has proposed a balancing charge based on the calculations described in Section XIV.A.2.b. above, which will change semiannually. The Company stated that it would be using LNG and storage assets to balance its system. Therefore, the Company assumes that customers would be out of balance at a time when the Company dispatches LNG and gas from storage. The Company's LNG and propane resources used to balance its transportation customers were acquired and developed for the benefit of the Company's firm sales customers. The Department anticipates that the majority of transportation customers will be former sales customers. The record in this case indicates that Boston Gas will not be required to modify its LNG and propane resources, and, therefore, will not have to assume additional costs to provide the proposed balancing service.

Distrigas argues that the Company's balancing charge should be increased to reflect the cost of the actual services covered by the charge. However, the record contains insufficient data to support Distrigas's position. Similarly, intervenors who argue for a lower balancing charge have not provided sufficient data to support their proposals.

In light of the above, the Department accepts the Company's proposal for developing and calculating its balancing charge.

7. Fee for Changing Suppliers

According to the Company, its proposed fee for customers changing suppliers is intended to recover administrative costs. However, the Company derived this fee without performing any cost analyses, and indicated that the fee is also intended to prevent customers from changing suppliers without "due consideration." The Department is concerned that (1) the level of this fee has been set without regard to actual costs, and (2) it may impose an additional financial burden on customers or their suppliers. Therefore, the Department rejects the Company's proposed fee for changing suppliers. The Department notes that this proposal could be re-examined in Phase II, provided that the Company supports its recommendation with a detailed analysis.

8. Agent Assignment

In response to concerns raised by certain intervenors, the Company has agreed to modify its initial proposal regarding the assignment of a supplier as an agent who would deal directly with the Company on behalf of the customer, and streamline the application process for transportation service through the use of voice authorization. Accordingly, the Department directs the Company to modify its proposed T&C to reflect this change in agent assignment.

9. Daily Index

While the record on Tennessee's proposal regarding the Daily Index is incomplete, the Department recognizes that differences in pricing between the pipelines serving Boston Gas may lead to gaming. Accordingly, the Department directs the Company to modify its definition of the Daily Index to reflect prices on the Tennessee pipeline system.

10. Designated Receipt Point

The Department notes that Boston Gas and Distrigas have agreed to identify the Distrigas interconnection as a designated receipt point. This agreement will allow Distrigas to deliver gas to customers who can physically be served from this point. Accordingly, the Department directs the Company to amend its proposed T&C to reflect this agreement.

11. Miscellaneous Issues

In addition to the above issues, various parties have proposed specific modifications to the Company's T&C as addressed below.

The Attorney General proposed that language be included in the Company's agreements with marketers, compelling marketers to act in accordance with consumer protection statutes. The Department finds that the Attorney General's proposal is unnecessary and redundant. Gas suppliers are expected to be in compliance with all relevant state and federal statutes and regulations, and therefore obligations imposed by the statutes and regulations identified by the Attorney General are implicit.

TMG argues that Boston Gas should not be allowed the discretion to reject a transportation request on the grounds that it may impair the Company's firm service obligations. The Department anticipates that the majority of transportation customers would be existing sales customers converting to transportation. Therefore, only new gas customers could impair the Company's firm service obligations. Accordingly, the Department directs the Company to amend its proposed T&C to reflect that only applications from new customers on the Company's distribution system or applications related to large new loads for historic sales customers may be rejected if their request for service may impair the Company's firm service obligations.

TMG has proposed that Boston Gas be precluded from developing standards for marketers. We note that a set of standards may be necessary to deter undesirable behavior from marketers. If Boston Gas desires to engage in this process, the Company should develop such standards for Department review in collaboration with all affected parties, including, but not limited to, the Attorney General, DOER, the other intervenors in this proceeding, and others conducting business in its service territory.

Regarding the Company's proposed force majeure provision, the Department notes that its wording appears to protect the Company not only from force majeure conditions, but also from its own negligence. Consequently, the Department directs Boston Gas to modify its force majeure proposal as follows: (1) breakage or accident to machinery or pipeline would not qualify as a force majeure event if it was a result of the Company's negligence or misconduct; and (2) in the event the Company is unable to restore service to a customer in 30 days, the customer (a) is immediately relieved of any further demand charge obligation, and (b) may, at its sole option, elect not to terminate the contract by providing Boston Gas with an additional 30 days to correct the service interruption.

TMG has raised issues for which the record does not, at this time, contain adequate information to conduct a meaningful analysis. Consequently, the Department rejects TMG's proposals regarding (1) allowing marketers to bill customers directly for transportation and commodity; (2) identification of suppliers; (3) allowing customers to convert between optional and general transportation service more frequently than once a year; (4) the Company's obligation to inform customers of any tariff changes;[166] and (5) changes to the

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166 This proposal is also redundant. The Department refers TMG to G.L. c. 164. § 94 governing notification in case of rate change.

Company's curtailment provisions. Finally, the Department, for the same reason, rejects TEC's proposal on combined metering. The Department notes, however, that these proposals relate to issues that may have a significant effect on the development of a robust competitive market. Therefore, the Department's rejection of TMG's and TEC's proposals is without prejudice to their further consideration during Phase II of this proceeding.

SCHEDULE 1

REVENUE REQUIREMENTS AND CALCULATION OF REVENUE INCREASE

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
COST OF SERVICE				
Total O&M Expense	$532,765,095	$2,161,973	($16,219,073)	$518,707,995
Depreciation & Amortization Exp.	42,702,483	(10,311)	(2,180,330)	40,511,842
Taxes Other Than Income Taxes	22,063,157	12,135	(1,122,103)	20,953,189
Income Taxes	17,563,491	2,385	(3,104,651)	14,461,225
Interest On Customer Deposits	154,061	0	0	154,061
Local Production & Storage Facilities*	0	0	(1,174,030)	(1,174,030)
Return On Rate Base	46,162,034	5,881	(4,306,507)	41,861,408
Total Cost Of Service	$661,410,322	$2,172,064	($28,106,695)	$635,475,692
OPERATING REVENUES				
Operating Revenues	653,073,094	0	0	653,073,094
Revenue Adjustments	(14,822,482)	(72,280)	194,642	(14,700,120)
Total Operating Revenues	638,250,612	(72,280)	194,642	638,372,974
Revenue Deficiency	$23,159,710	$2,244,344	($28,301,337)	($2,897,282)
Balance of PBOP Phase-In Ordered in D.P.U. 93-60	2,569,231	0	(2,569,231)	$0
Total Increase in Revenues as of December 1, 1996	$25,728,941	$2,244,344	($30,870,568)	($2,897,282)

* This adjustment includes various components reflected in the other cost of service items.

SCHEDULE 2

OPERATIONS AND MAINTENANCE EXPENSES

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Purchased Gas Expense	$375,202,673	$0	$0	$375,202,673
Other O&M Expense	157,470,423	0	0	$157,470,423
O&M Expense Per Books	532,673,096	0	0	532,673,096
ADJUSTMENTS TO PURCHASED GAS EXPENSE:				
Gas Cost Adjustment	0	0	0	0
C&LM Salaries Adjustment	0		0	0
Total Adj. to Purchased Gas Expense	0	0	0	0
ADJUSTMENTS TO OTHER O&M EXPENSE:				
1996 Wage & Salary Expense *	3,238,983	1,202,799	(173,600)	4,268,182
1995 Wage & Salary Overtime Normalize	2,516,842	0	(2,516,842)	0
Wage & Salary Quest Reduction	(3,283,444)	0	(597,397)	(3,880,841)
Health Care Expense	(235,751)	0	0	(235,751)
Dental Care Expense	(48,399)	0	0	(48,399)
Long-Term Disability Insurance Expense	99,857	0	0	99,857
Group Life Insurance Expense	321,757	0	0	321,757
Bad Debt Expense	(572,390)	553,262	(9,027,147)	(9,046,275)
AGA Dues Expense	(24,692)	0	0	(24,692)
Public Relations Expense	(41,405)	0	0	(41,405)
Public Liability Expense	169,318	0	0	169,318
Quest Program Costs	(2,793,445)	0	(2,307,852)	(5,101,297)
Charitable Contribution Expense	(358,617)	0	0	(358,617)
Customer Communication Expense	498,395	0	(498,395)	0
Personal Computer Lease Expense	241,233	0	0	241,233
Waltham Lease Expense	90,321	0	0	90,321
Unbundling Proceeding Expense	101,443	(1,000)	0	100,443
Lobbying Related Expense	(104,320)	0	0	(104,320)
Telemetering Expense	45,552	0	(45,552)	0
ECS Expense	(946,191)	0	0	(946,191)
1996 Inflation Allowance *	1,176,952	406,912	(60,551)	1,523,313
Advertising Expense	0	0	(79,713)	(79,713)
Salem LNG Tank Amort Expense	0	0	(52,842)	(52,842)
Pension Expense	0	0	(878,053)	(878,053)
PBOP Expense	0	0	169,683	169,683
Penalties	0	0	(12,853)	(12,853)
Benefits of Unfilled Positions due to Quest	0	0	(137,400)	(137,400)
Gain on Sale of Land	0	0	(559)	(559)
Total Adj. to Other O&M Expense	91,999	2,161,973	(16,219,073)	(13,965,101)
Total Adjustments to O&M Expense	91,999	2,161,973	(16,219,073)	(13,965,101)
Adjusted Total O&M Expense	$532,765,095	$2,161,973	($16,219,073)	$518,707,995

* Company adjustment reflects RR-AG-5 and Exh. BGC-39 at 33-34.

SCHEDULE 3

DEPRECIATION AND AMORTIZATION EXPENSES

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Depreciation & Amortization Exp.	42,702,483	(10,311)	(2,180,330)	40,511,842
Total Depreciation & Amort. Exp.	$42,702,483	($10,311)	($2,180,330)	$40,511,842

SCHEDULE 4

RATE BASE AND RETURN ON RATE BASE

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	764,050,013	(195,194)	(31,213,705)	732,641,114
LESS:				
Reserve For Depreciation	251,653,983	(5,656)	(20,349,574)	231,298,753
Net Utility Plant in Service	512,396,030	(189,538)	(10,864,131)	501,342,361
ADDITIONS TO PLANT:				
Cash Working Capital	18,130,470	248,775	(1,866,304)	16,512,941
Materials and Supplies	5,175,474	0	0	5,175,474
Total Additions to Plant	23,305,944	248,775	(1,866,304)	21,688,415
DEDUCTIONS FROM PLANT:				
Reserve for Deferred Inc. Taxes	71,055,573	949	(1,453,000)	69,603,522
Unamortized ITC - Pre 1971	154,988	0	0	154,988
Customer Deposits	2,789,175	0	0	2,789,175
Deferred Service Contract Revenue	3,975,611	0	0	3,975,611
Unclaimed Funds	223,817	0	0	223,817
Total Deductions from Plant	78,199,164	949	(1,453,000)	76,747,113
RATE BASE	457,502,810	58,288	(11,277,435)	446,283,663
COST OF CAPITAL	10.09%	0.00%	-0.71%	9.38%
RETURN ON RATE BASE	46,162,034	5,881	(4,306,507)	41,861,408

SCHEDULE 5

COST OF CAPITAL

	PER COMPANY			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$210,000,000	46.24%	8.12%	3.75%
Preferred Stock	30,000,000	6.61%	6.62%	0.44%
Common Equity	214,197,065	47.16%	12.50%	5.90%
Total Capital	$454,197,065	100.00%		10.09%
Weighted Cost of				
Debt				3.75%
Equity				6.34%
Cost of Capital				10.09%

	PER COMPANY - ADJUSTED			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$210,000,000	46.24%	8.12%	3.75%
Preferred Stock	30,000,000	6.61%	6.62%	0.44%
Common Equity	214,197,065	47.16%	12.50%	5.90%
Total Capital	$454,197,065	100.00%		10.09%
Weighted Cost of				
Debt				3.75%
Equity				6.34%
Cost of Capital				10.09%

	PER ORDER			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$210,000,000	46.24%	8.12%	3.75%
Preferred Stock	30,000,000	6.61%	6.62%	0.44%
Common Equity	214,197,065	47.16%	11.00%	5.19%
Total Capital	$454,197,065	100.00%		9.38%
Weighted Cost of				
Debt				3.75%
Equity				5.63%
Cost of Capital				9.38%

SCHEDULE 6

CASH WORKING CAPITAL

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Other O&M Expense	157,562,422	2,161,973	(16,219,073)	143,505,322
Total Amount Subject to Cash Working Capital Allowance	157,562,422	2,161,973	(16,219,073)	143,505,322
Cash Working Capital Allowance (Total times 42/365)	18,130,470	248,775	(1,866,304)	16,512,941

SCHEDULE 7

TAXES OTHER THAN INCOME TAXES

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
FICA TAXES	5,778,648	0	(53,514)	5,725,134
Federal Unemployment Taxes	81,701	0	(672)	81,029
State Unemployment Taxes	793,493	0	(7,128)	786,365
State Use Taxes	75,948	0	0	75,948
Automobile Excise Tax	120,343	0	0	120,343
Property Taxes	15,213,024	12,135	(1,060,789)	14,164,370
Total Taxes Other Than Income	22,063,157	12,135	(1,122,103)	20,953,189

SCHEDULE 8

INCOME TAXES

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	457,502,810	58,288	(11,277,435)	446,283,663
Return on Rate Base	46,162,034	5,881	(4,306,507)	41,861,408
LESS:				
Interest Expense	17,156,355	2,186	(422,904)	16,735,637
ADD:				
Net Permanent Tax Differences	127,671	0	0	127,671
Amort of TEFRA Basis Adjustment	29,018	0	0	29,018
Amort of Investment Tax Credit	(936,389)	0	0	(936,389)
Amort Excess Deferred Inc Taxes	(209,405)	0	0	(209,405)
Amort Deficient Deferred Inc Taxes	363,522	0	(363,522)	0
Total Additions	(625,583)	0	(363,522)	(989,105)
Taxable Income Base	28,380,095	3,695	(4,247,125)	24,136,665
Taxable Income (Taxable Income Base times 1.6454)	46,696,610	6,082	(6,988,220)	39,714,469
Mass Franchise Tax (6.5 Percent)	3,035,280	395	(454,234)	2,581,440
Federal Taxable Income	43,661,330	5,686	(6,533,986)	37,133,027
Federal Income Tax Calculated	15,281,465	1,990	(2,286,895)	12,996,560
Total Income Taxes Calculated	18,316,745	2,385	(2,741,129)	15,577,999
Amort of TEFRA Basis Adjustment	29,018	0	0	29,018
Amort Investment Tax Credit	(936,389)	0	0	(936,389)
Amort Excess Deferred Inc Taxes	(209,405)	0	0	(209,405)
Amort Deficient Deferred Inc Taxes	363,522	0	(363,522)	0
Total Income Taxes	17,563,491	2,385	(3,104,651)	14,461,225

SCHEDULE 9

REVENUES

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Operating Revenues per Books	653,073,094	0	0	653,073,094
Revenue Adjustments				
Weather Adjustment	307,889	0	194,642	502,531
Billing Day Adjustment	1,078,640	(72,280)	0	1,006,360
Interest on Deferred Gas Costs	(4,413,118)	0	0	(4,413,118)
Gas Cost Working Capital Allowance	(6,259,963)	0	0	(6,259,963)
ECS Revenues	(946,191)	0	0	(946,191)
NEES Settlement	(1,505,739)	0	0	(1,505,739)
DSM Lost Margins/Incentives	(3,084,000)	0	0	(3,084,000)
Total Revenue Adjustments	(14,822,482)	(72,280)	194,642	(14,700,120)
Adjusted Total Operating Revenues	638,250,612	(72,280)	194,642	638,372,974

BOSTON GAS COMPANY, D.P.U. 96-50

PER ORDER BASE REVENUE INCREASE ($2,897,282)

PEAK SEASON

RATE CLASS	TEST YEAR CGA REVENUES (A)	NORMAL TEST YEAR BASE REVENUES (B)	PROPOSED REVENUE INCREASE AT EROR (C)	PER ORDER ADJUSTMENT TO EROR INCREASE (D)	PER ORDER ADJUSTMENT TO INCREASE (E)	SEASONAL REVENUE REALLOCATION (F)	PER ORDER PROD.&STOR DECREASE (G)	TARGET BASE REVENUE EXCLD LI DEF & SEASONAL REALLOCATION (H)	ALLOCATION LOW INCOME DEFICIENCY (I)	PER ORDER BASE REVENUE (J)	(%) BASE REVENUE INCREASE (K)	PER ORDER CGA REVENUES (L)	TOTAL REVENUE (M)	(%) TOTAL REVENUE INCREASE (N)
RESIDENTIAL														
NONHEAT (R-1 &R-2)	$11,309,754	$15,506,000	$1,184,000	($1,566,706)	$0	($38,821)	$57,590	$15,065,704	($128,249)	$14,898,634	-3.92%	$11,814,579	$28,513,213	-1 13%
HEAT (R-3 & R-4)	$165,621,656	$104,631,000	($9,145,000)	($8,863,360)	$0	$13,686,195	$591,625	$85,930,815	($1,064,661)	$98,552,349	-5.81%	$170,290,952	$268,843,301	-0 60%
COMMERCIAL (LLF)														
G-41	$13,346,150	$8,432,000	($304,000)	($762,983)	$36,791	$1,300,000	$50,635	$7,351,173	$145,177	$8,796,350	4.32%	$13,705,861	$22,502,211	3 32%
G-42	$17,940,630	$8,757,000	($369,000)	($787,389)	$37,924	$900,000	$60,905	$7,577,630	$176,712	$8,654,342	-1.17%	$18,424,379	$27,078,721	1 43%
G-43	$40,110,354	$15,509,000	$392,000	($1,492,642)	$71,830	$500,000	$127,655	$14,352,334	$360,009	$15,212,342	-1.91%	$41,191,425	$56,403,767	1 41%
G-44/G-45	$14,364,357	$7,102,000	($257,000)	($642,547)	$30,895	$120,000	$60,190	$6,173,159	$165,686	$6,458,845	-9.06%	$14,751,511	$21,210,356	-1.19%
COMMERCIAL (HLF & SLF)														
G-51/G-61	$4,659,448	$3,357,000	$275,000	($340,939)	$16,466	$92,635	$17,485	$3,290,042	$56,506	$3,439,182	2.45%	$4,785,031	$8,224,214	2 59%
G-52/G-62	$6,919,139	$2,912,000	$473,000	($317,753)	$15,320	($189,719)	$21,515	$3,061,052	$65,495	$2,936,828	0.85%	$7,105,627	$10,042,454	2 15%
G-53/G-63	$11,463,966	$4,408,000	$400,000	($451,331)	$21,740	$0	$34,580	$4,343,628	$101,471	$4,445,300	0.85%	$11,772,948	$16,218,248	2 18%
G-54/G-55	$3,856,354	$4,261,000	$520,000	($450,674)	($11,588)	$175,000	$46,150	$4,292,586	$116,616	$4,586,204	7.13%	$3,960,292	$8,546,496	5.03%
TOTAL	$289,792,008	$174,895,000	($8,831,000)	($15,776,324)	$219,379	$16,545,290	$1,068,730	$151,436,325	($3,239)	$167,980,376	-3.95%	$297,602,805	$465,582,981	0.19%

OFF-PEAK SEASON

RATE CLASS	TEST YEAR CGA REVENUES (A)	NORMAL TEST YEAR BASE REVENUES (B)	PROPOSED REVENUE INCREASE AT EROR (C)	PER ORDER ADJUSTMENT TO EROR INCREASE (D)	PER ORDER ADJUSTMENT TO INCREASE (E)	SEASONAL REVENUE REALLOCATION (F)	PER ORDER PROD.&STOR DECREASE (G)	TARGET BASE REVENUE EXCLD LI DEF & SEASONAL REALLOCATION (H)	ALLOCATION LOW INCOME DEFICIENCY (I)	PER ORDER BASE REVENUE (J)	(%) BASE REVENUE INCREASE (K)	PER ORDER CGA REVENUES (L)	TOTAL REVENUE (M)	(%) TOTAL REVENUE INCREASE (N)
RESIDENTIAL														
NONHEAT (R-1 &R-2)	$3,346,814	$12,623,000	$2,248,000	($1,395,955)	$0	$38,821	$24,570	$13,450,475	($136,101)	$13,351,195	5.77%	$3,437,019	$16,788,214	5 12%
HEAT (R-3 & R-4)	$13,585,954	$31,759,000	$21,591,000	($5,008,014)	$0	($13,686,195)	$61,295	$48,280,691	($280,006)	$34,314,490	8.05%	$13,952,128	$48,266,618	6 44%
COMMERCIAL (LLF)														
G-41	$648,238	$2,691,000	$1,866,000	($427,770)	$20,735	($1,300,000)	$6,690	$4,143,075	$54,076	$2,897,151	7.66%	$665,710	$3,562,861	6 70%
G-42	$1,285,281	$2,376,000	$1,303,000	($345,351)	$16,754	($900,000)	$2,730	$3,347,673	$55,713	$2,503,396	5.36%	$1,299,383	$3,802,769	4 43%
G-43	$3,448,350	$4,531,000	$1,060,000	($524,832)	$25,471	($500,000)	$2,275	$5,089,364	$94,768	$4,684,132	3.38%	$3,541,291	$8,225,423	3 08%
G-44/G-45	$2,689,792	$1,554,000	$374,000	($180,983)	$6,786	($120,000)	$325	$1,755,478	$39,383	$1,674,660	7.78%	$2,762,288	$4,437,149	4 56%
COMMERCIAL (HLF & SLF)														
G-51/G-61	$1,150,938	$2,420,000	$408,000	($265,487)	$12,870	($92,634)	$3,900	$2,571,503	$36,753	$2,515,622	3.95%	$1,181,959	$3,697,580	3 55%
G-52/G-62	$1,894,409	$2,268,000	($5,000)	($212,430)	$10,306	$189,719	$1,560	$2,059,317	$37,009	$2,286,044	0.80%	$1,945,468	$4,231,512	1 66%
G-53/G-63	$2,863,755	$2,457,000	$317,000	($280,398)	$12,637	$0	$1,170	$2,525,069	$49,604	$2,574,674	4.79%	$2,940,940	$5,515,614	3 66%
G-54/G-55	$2,172,332	$1,245,000	$851,000	($196,753)	($326,928)	($175,000)	$390	$1,571,928	$47,599	$1,444,527	16.03%	$2,230,882	$3,675,409	7 55%
TOTAL	$33,065,863	$63,924,000	$30,013,000	($8,817,954)	($219,368)	($16,545,289)	$105,105	$84,794,573	($3,203)	$68,246,062	6.76%	$33,957,068	$102,203,150	5 38%

TOTAL PEAK + OFF-PEAK

RATE CLASS	TEST YEAR CGA REVENUES (A)	NORMAL TEST YEAR BASE REVENUES (B)	PROPOSED REVENUE INCREASE AT EROR (C)	PER ORDER ADJUSTMENT TO EROR INCREASE (D)	PER ORDER ADJUSTMENT TO INCREASE (E)	SEASONAL REVENUE REALLOCATION (F)	PER ORDER PROD.&STOR DECREASE (G)	TARGET BASE REVENUE EXCLD LI DEF (H)	ALLOCATION LOW INCOME DEFICIENCY (I)	PER ORDER BASE REVENUE (J)	(%) BASE REVENUE INCREASE (K)	PER ORDER CGA REVENUES (L)	TOTAL REVENUE (M)	(%) TOTAL REVENUE INCREASE (N)
RESIDENTIAL														
NONHEAT (R-1 &R-2)	$14,656,568	$28,129,000	$3,432,000	($2,962,660)	$0	$0	$82,160	$28,516,180	($266,350)	$28,249,829	0.43%	$15,051,598	$43,301,427	1 21%
HEAT (R-3 & R-4)	$179,407,610	$136,390,000	$12,446,000	($13,971,374)	$0	$0	$653,120	$134,211,506	($1,344,667)	$132,866,839	-2.58%	$184,243,080	$317,109,919	0 42%
COMMERCIAL (LLF)														
G-41	$13,994,388	$11,123,000	$1,562,000	($1,190,753)	$57,526	$0	$57,525	$11,494,246	$199,252	$11,693,501	5.13%	$14,371,571	$26,065,072	3 77%
G-42	$19,206,111	$11,133,000	$934,000	($1,132,741)	$54,679	$0	$63,635	$10,925,303	$232,425	$11,157,728	0 22%	$19,723,762	$30,881,490	1 79%
G-43	$43,558,704	$20,040,000	$1,452,000	($2,017,474)	$97,301	$0	$130,130	$19,441,697	$454,777	$19,896,474	-0 72%	$44,732,717	$64,629,191	1 82%
G-44/G-45	$17,054,149	$8,656,000	$117,000	($823,530)	$39,661	$0	$60,515	$7,928,636	$205,069	$6,133,705	-6 03%	$17,513,800	$25,647,505	-0 24%
COMMERCIAL (HLF & SLF)														
G-51/G-61	$5,810,386	$5,777,000	$683,000	($606,406)	$29,336	$1	$35,750	$5,847,180	$93,259	$5,940,439	2 83%	$5,966,990	$11,907,429	2 76%
G-52/G-62	$8,813,548	$5,180,000	$468,000	($530,183)	$25,626	$0	$46,540	$5,096,903	$102,504	$5,199,407	0 37%	$9,051,094	$14,250,502	1 84%
G-53/G-63	$14,327,721	$6,865,000	$717,000	($711,729)	$34,377	$0	$0	$6,904,648	$151,076	$7,055,724	2.78%	$14,713,888	$21,769,612	2 72%
G-54/G-55	$6,028,686	$5,526,000	$1,371,000	($647,428)	($338,516)	$0	$46,540	$5,864,516	$166,215	$6,030,731	9 13%	$6,191,174	$12,221,905	5 77%
STREET LIGHTING														
G-7	$146,258	$613,000	($336,000)	($26,002)	$29,500	$0	$390	$280,108	$5,496	$285,603	N/A	$150,200	$435,803	-42 60%
G-17	$33,896	$1,000	$59,000	($5,632)	($29,500)	$0	$65	$24,803	$946	$25,749	N/A	$34,810	$60,558	73 54%
TOTAL CORE	$323,038,025	$239,433,000	$22,905,000	($24,625,912)	$10	$1	$1,176,370	$238,535,728	$0	$236,535,729	-1.21%	$331,744,683	$568,280,412	1.03%

BOSTON GAS COMPANY D.P.U. 96-50

SCHEDULE 10 COLUMN IDENTIFICATION

COLUMN

(A)	Exh. AG-56
(B)	Exh. BGC-110, p. 29, ln. 5; Exh. AG-21, col. d
(C)	Exh. BGC-110, p. 29, ln. 17; Exh. AG-21, col. e
(D)	(D)=[Per Order Base Rev. Increase - (C)Total]*[[(B)+(C)]/[[(B)Total+(C)Total]]
(E)	PER RATE BY RATE ANALYSIS
(F)	PER RATE BY RATE ANALYSIS
(G)	RR-DPU-78, Sch. 29-1, ln. 26
(H)	(H)=(B)+(C)+(D)+(E)-(G)
(I)	ALLOCATED ON THE BASIS OF RATE BASE. FINAL RATES BASED ON THREE INTERATIONS.
(J)	(J)=(H)+(I)+(F)
(K)	(K)=[(J)-(B)]/(B)
(L)	(L)=(A)+(G)+BAD DEBT REVENUES PER ORDER
(M)	(M)=(L)+(J)
(N)	(N)=[(M)-[(A)+(B)]]/[(A)+(B)]

XVI. ORDER

Accordingly, after due notice, hearing, and consideration, it is hereby

ORDERED: That the tariffs M.D.P.U. Nos. 944 through 970, filed by Boston Gas Company on May 17, 1996, to become effective June 1, 1996, be and hereby are DISALLOWED; and it is

FURTHER ORDERED: That Boston Gas Company file new schedules of rates and charges designed to reduce base revenues by $2,897,282, and it is

FURTHER ORDERED: That Boston Gas Company shall file all rates and charges required by the Order and shall design all rates in compliance with this Order; and it is

FURTHER ORDERED: That Boston Gas Company shall comply with all other orders and directives contained herein; and it is

FURTHER ORDERED: That the new rates shall apply to gas consumed on or after the date of this Order, but unless otherwise ordered by the Department, shall not become effective earlier than seven (7) days after they are filed with supporting data demonstrating that such rates comply with this Order.

By Order of the Department,

John B. Howe

John B. Howe, Chairman

Janet Gail Besser

Janet Gail Besser, Commissioner

A true copy
Attest:

MARY L. COTTRELL
Secretary

Appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part.

Sudh petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court siting in Suffolk County by filing a copy thereof with the Clerk of said Court. (Sec. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).